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Full Name of Author — Nom complet de l'auteur

PHILLIP CHAN

Date of Birth — Date de naissance

15 MAY 1950

Country of Birth — Lieu de naissance

HONG KONG

Permanent Address — Résidence fixe

5107 MARIAN ROAD N.E.
CALGARY, ALTA. T2A 2Y1

Title of Thesis — Titre de la thèse

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Dr. D. L. FLOCK

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THE EMULSIFICATION OF OIL BY SODIUM HYDROXIDE AS A FORM OF VISCOUS OIL RECOVERY

BY

PHILLIP CHAN

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "THE EMULSIFICATION OF OIL BY SODIUM HYDROXIDE AS A FORM OF VISCOUS OIL RECOVERY", submitted by Phillip Chan, in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

Supervisor

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ABSTRACT

An experimental study using native sand and fluids was conducted to investigate the effects of sodium hydroxide on the waterflood recovery of viscous crude oil.

The oil recovery data from caustic waterfloods in two different diameter cores were compared to that observed for a conventional waterflood in the same cores. It was found that sodium hydroxide caused the formation of oil-in-water emulsions in the fluids recovered from the 2 inch diameter cores. Emulsions were formed in only one caustic flood involving a 1½ inch diameter core.

For the 2" cores which produced emulsions, the average amount of oil recovered in the sodium hydroxide flood was as high as 72% of the original oil in place at 1.5 cumulative pore volume of water injection. The average oil recovery from the waterfloods on the same cores was only 40% of the original oil in place at the same amount of water injection.

The producing water-to-oil ratio (W.O.R.) of the effluent from the waterfloods increased monotonically after initial water production. The fluids recovered from the caustic floods which produced emulsions, however, had a much lower water-to-oil ratio at all stages of the flood. Moreover, even after the W.O.R. started to increase at the later portion of the caustic flood, this increase

was not sustained. The W.O.R. decreased sharply after reaching a high value temporarily, then increased again until oil recovery essentially ceased.

It was concluded that emulsification of the viscous oil in place was the primary process responsible for the increased oil recovery. A part of the emulsions was entrained in the flood water and produced. The balance of the emulsions were entrapped in the more permeable sections of the cores where the pore throats were not large enough for them to pass through. This blockage caused the source water injected after the caustic slug to be diverted to the less permeable and smaller pore throats where the otherwise immobile oil was swept out and produced. As a result, there was an increase not only in pressure drop across the cores, but also chloride ion concentration of the effluent and ultimate oil recovery. In addition, it was observed that the sodium hydroxide appeared to need a minimum residence time to react with the crude oil to produce oil-in-water emulsions.

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INTRODUCTION

There is a large number of known viscous crude oil deposits throughout the world. However, due to their high viscosities, only a small fraction of their oil-in-place may be recovered by conventional enhanced oil recovery methods such as waterflooding.

It has been shown that the waterflood recovery of viscous oils in laboratory experiments may be improved by the addition of certain chemicals, such as sodium hydroxide, to the flood water. Scott, G. R. (1) found that a low concentration of sodium hydroxide in the flood water significantly increased oil recovery from cores through the reduction of water-oil interfacial tension. He also reported that his sand system was more water wet after the caustic floods. Scott, J. D. (2) carried out similar experiments. He showed that extremely low interfacial tensions existed between crude oil and sodium hydroxide solutions having a pH of 10.0 approximately. Oil recovery from cores was greatly improved by injecting a 0.1% by weight sodium hydroxide solution.

Gardiner (3) added sodium hydroxide to only a portion of the injected fluids used for flooding a core pack. He also found that sodium hydroxide caused a reduction of the oil-water interfacial tension and a shift in the system wettability from oil wet to neutral or water wet. Slugs of sodium hydroxide, 0.1% by weight concentration and 0.4

pore volumes in size, were injected into cores and the oil recovered was equivalent to that obtained by adding sodium hydroxide to all of the injected fluid.

All of the above authors reported the presence of emulsions in the effluent from the cores when sodium hydroxide was used as the injection fluid but did not postulate this mechanism as an essential criterion for an increase in recovery.

The purpose of this study was to investigate whether the formation or production of emulsions is necessary to improve the recovery of a viscous crude oil (Wainwright crude) when using NaOH. The experiments performed in this study differed from the above mentioned work in that actual produced reservoir fluids, crude oil and water, from the Wainwright oil field were used. The above investigators only employed artificial brine as the water phase in the core system.

It is known that the formation of emulsions is facilitated by the presence of emulsifiers. Some investigators have shown (9) (21) that these emulsifiers may be produced by the chemical reaction between caustic water and viscous crude oils. The presence of these emulsifiers at the water-oil interface causes the lowering of interfacial tension which assists in the formation of emulsions.

As a preliminary step in this study, the interfacial tension between the viscous Wainwright crude oil and source water* was determined. The identical procedure was repeated for caustic solutions in source water and the same crude oil. A lower interfacial tension between the caustic solution and crude oil will indicate that they have reacted to form emulsifiers. This observation suggests that when caustic is used to displace the same crude oil from cores, emulsions may be formed under certain conditions.

If the oil recovery is increased by using NaOH to emulsify the oil, then the conditions under which the oil is emulsified would be most crucial to future field applications. One of these conditions is the contact time between the oil and caustic before emulsions are formed.

In order to study how emulsification of oil may increase recovery and the conditions of emulsification, displacement tests were performed. Cores saturated with a viscous crude oil and native water**, at irreducible saturation, were flooded with source water. The waterflood oil recovery data served as a standard for comparison of results. The cores were resaturated and partially flooded with source water. Slugs of sodium hydroxide of various concentrations were then injected,

* Source water is water obtained from source wells for use in injection wells.

** Native water is water produced in association with crude oil from a producing well.

followed by source water. The tests were performed on partially waterflooded cores to simulate starting conditions similar to those expected in the heavy oil producing areas of Alberta. The results of these caustic waterfloods were compared to the standards, particulary with regard to the character of the produced fluids in the form of emulsions and in terms of any increase in oil recovery.

During the caustic waterfloods, pressure behavior, water-oil ratio of the effluent, pH and sodium hydroxide concentration in the produced fluids was monitored in an attempt to study insitu emulsification behavior and displacement efficiency. Two different diameter cores were used in the investigation to study the possible effect of core diameters on the mixing and thus emulsification behavior of the fluids during a displacement process.

LITERATURE REVIEW

A. History

The use of sodium hydroxide and alkaline salts in the waterflood recovery of crude oils dates back to 1917. At that time Squires (4) found that by introducing an alkali into the water, the displacement of oil from sand was made more complete.

Beckstrom and Van Tuyl (5) published the results of a series of flooding experiments on oil sands in 1926. They found that dilute solutions of sodium hydroxide, at lower concentrations, down to 1%, were more effective than high concentrations in increasing the yield of oil. Higher oil recovery was obtained when the experimental temperature was increased.

Uren and Fahmy (6) carried out further investigations on the effects of chemicals on oil recovery during 1927. They concluded that sodium hydroxide might be the most effective of all the reagents used. They suggested that for release of adherent oil from oil wet sand grains, the interfacial tension between the oil and the mineral composing the sand must be greater than the sum of the interfacial tensions between the water and the mineral and between the flood water and the oil.

In 1927, Atkinson (7) obtained the first patent on flooding oil bearing sands with water containing caustic alkalis. He recognized that the capillarity and adhesive property of the

oil will cause it to wet and adhere as films to sand grains. The viscosity of the oil will enhance this trapping of the oil. When a secondary recovery method such as waterflood was initiated, it could not overcome these forces. By adding caustic alkali, the tension at the oil water interface will be modified, bringing about the displacement of oil by the water more readily.

B. Recent Developments

Since the 1930's, a lot of work on the use of sodium hydroxide in oil recovery has been carried out. Johnson (7) made a very thorough review on this subject recently. He classified all the mechanisms, proposed by different authors by which caustic waterflooding helps to increase oil recovery, into 4 types:

(1) Emulsification and entrainment

(2) Emulsification and entrapment

(3) Wettability reversal (oil wet to water wet)

(4) Wettability reversal (water wet to oil wet)

(1) Emulsification and Entrainment

In 1942, Subkow (9) patented a method for the removal of petroleum (bitumen) from bituminous deposits. He described the use of an alkaline solution which depressed the interfacial tension between the bitumen and water and also caused the formation of emulsifying agents. The emulsifying agents were formed from reactions between sodium hydroxide and the acidic constituents originally present in the bitumen. As a result the

bitumen was emulsified into an oil-in-water type of emulsion and thereby stripped from the surface of the mineral sand grains. The emulsions were then entrained into a continuous flowing alkaline water phase and produced along with the flowing alkaline solution.

Subkow suggested that, with regard to its emulsifying capabilities, excessive concentrations of the alkali should be avoided (2-3% by weight are usually sufficient). Excessive quantities of the alkali could cause the formation of an inverted water-in-oil emulsion, or by virtue of the alkali's electrolytic concentration, prevent the formation of any emulsion. This process could be applied not only to viscous bituminous deposits but also for removal of residual oil deposits from exhausted oil fields.

Reisberg and Doscher (10) performed oil displacement tests on a consolidated sandstone and an unconsolidated sand pack saturated with oil. In the unconsolidated core they used a mixture of surfactant and crude oil to displace the oil. The consolidated cores were flooded with an aqueous solution of sodium hydroxide or a mixture of sodium hydroxide and surfactant.

They concluded that sodium hydroxide did increase the oil recovery from the consolidated cores. However, the increase in recovery occurred only after the effluent became alkaline. The lowering of interfacial tension and the formation and

production of oil-in-water emulsions was the main mechanism for additional oil recovery. The ability of the caustic to prevent adherence of oil to sand surface and to suppress semi-solid film formation at the oil-water interface was also thought to play a part.

Reisberg and Doscher concluded that adsorption on and the reaction with rock, and displacement of connate water would cause the alkali to fall behind the oil-water displacement front. They thought, as a result of this, no increase in oil recovery would be realised until water breakthrough and that extra oil would be produced only after several pore volumes of caustic had been injected, an economically unfavorable situation for field application.

(2) Emulsification and Entrapment

Jennings et al (21) proposed a second mechanism by which caustic injection could improve oil recovery. This mechanism again involved the lowering of interfacial tension between oil and water by the reaction between caustic and the potentially surface active organic acids in the crude oil, thereby causing the emulsification of crude oil insitu. The emulsions became entrained in the flowing caustic until they reached pore throats too small for them to pass through. The emulsions were trapped and as a result would reduce water mobility, improving both vertical and areal sweep efficiency.

Since the emulsified oil was entrapped again and could not be produced, the residual oil retained by capillary action would not be reduced significantly. Consequently, this mechanism is suitable for viscous oils in heterogeneous reservoirs where sweep efficiency is poor. The improvement in mobility control would increase vertical and areal sweep efficiency which could be more important economically than increasing recovery of residual oil from the comparatively small volume of the reservoir normally swept.

(3) Wettability Reversal-Oil Wet to Water Wet

Wagner and Leach (22) performed experiments which showed improved oil recovery through the use of chemical solutions. The chemicals reversed rock wettability from oil wet to water wet. They concluded from their tests that the efficiency with which water displaced oil from a porous media was related to the nature of capillary forces present. These in turn were controlled by the preferential wetting of the solid by the two fluids.

The improvement in oil recovery resulted largely from favourable changes in relative oil and water permeabilities which accompanied a reversal from oil wet to water wet in a region where oil was still flowing. This change in permeabilities also provided a more favourable mobility ratio. Even after some plain waterflooding had taken place, the improved mobility could halt the gradual increase in producing WOR.

Another conclusion they drew was that the injected chemical always would be preceded by displaced connate water so that the chemical solution would encounter only the residual oil left behind the untreated, connate water flood front. Since residual oil in a water wet porous media is discontinuous and immobile, as compared with the continuous residual oil phase in an oil-wet porous media, they suggested that water-wet rocks would not respond to a wettability reversal mechanism. Therefore they limited the application of this process to oil-wet reservoirs where wettability could be reversed from oil-wet to water-wet. Oil remaining behind the depleted leading edge of the flood water in oil-wet reservoirs might be continuous so that oil released by reversing the wettability could be recovered.

The chemicals which they used were acidic solutions, but these were found to be impractical because the acids were too reactive with most reservoir rocks.

As a result of this, Leach et al (23) used sodium hydroxide and obtained similar results as above in laboratory tests. A field test was also performed. It was concluded that wettability reversal from oil to water wet and the increase in oil recovery was obtained from that portion of the reservoir invaded.

Mungan (24) performed the same type of laboratory displacement tests as Leach et al, using sodium hydroxide. He

found that the process was temperature dependent. Optimum results were observed at 160 ^{o}F; at 70 ^{o}F there were no beneficial results obtained using caustic as a flooding agent. After the core was made water wet from oil wet, the relative permeability to water was lower, creating a more favorable water-oil mobility ratio even at high water saturation values.

(4) Wettability Reversal -- Water-Wet to Oil-Wet

Cooke et al (25) reported a fourth mechanism whereby caustic increased oil recovery. They observed that soaps were formed at the oil/water interface when organic acids, naturally occuring in some crude oils, reacted with sodium hydroxide solutions. The interfacial tension was lowered drastically. The wettability of the porous media was changed to preferentially oil wet under proper conditions of salinity, pH and temperature. As a result of this change in wettability, a viscous water-in-oil emulsion was formed.

The most important criterion for this mechanism to become effective was that the alkaline water must be saline, rather than fresh. The presence of salt rendered the soaps practically insoluble in the alkaline water. The soaps then promoted the oil wetting of the matrix. In fresh water, soaps were soluble and promoted water wetting.

A high, non-uniform pressure gradient was generated across the narrow region in the vicinity of the emulsion front due to the flow properties of the water-in-oil emulsions. This pressure gradient was sufficient to overcome the reduced capillary forces and displaced the oil from the porous media. A sharp gradient in oil saturation was observed at the displacement front as well. This was attributed to the fact that a low mobility of fluid was experienced where the emulsions were present and that the oil content of the water-in-oil emulsions was comparatively lower than the oil saturation behind the emulsion front.

C. Reaction of Sodium Hydroxide with Reservoir Systems

As described above, sodium hydroxide will react with carboxylic acids of the crude oil in the reservoir to form soaps, thereby triggering the mechanisms for increased oil recovery.

The sodium hydroxide does not react with the crude oil alone. As it progresses with the flood water in the reservoir it will also be consumed by the mineral matter of the reservoir rock and the connate water 'native' to the reservoir.

(a) Sodium hydroxide may react with different components of the reservoir rock, depending on the composition of the rock.

(i) Reaction with Calcium Sulfate Minerals

Strong caustic solutions will dissolve calcium sulfate minerals (gypsum, anhydrite) (26). Calcium hydroxide is precipitated, resulting in a loss of alkalinity and an increase in sulfate concentration. As the sulfate ion concentration increases, the calcium sulfate will be less soluble. An equilibrium will be reached just before the complete neutralization of the caustic. Calcium hydroxide does not help in improving oil recovery in any way. As such, the caustic consumed is merely wasted. Experiments (26) show that when a solution of 5% sodium hydroxide contacts an excess of gypsum, an equilibrium point, at which no further reaction takes place, is reached at a concentration of about 1% sodium hydroxide.

ii) Reaction with Quartz

It is generally (26) found that sodium hydroxide will react very slowly and incompletely with quartz to give a soluble sodium silicate. This sodium silicate solution has been found to be effective in wettability alteration (27).

(iii) Reaction with Clay (25)

Clays are commonly present in reservoir rocks. They also have a very high surface area. Therefore these materials play an important part in alkaline water displacement processes.

As pH of the water is increased, ions such as hydrogen ions on the surface of the clays will react with hydroxide ions in the flood water, lowering the pH of the water. The caustic will be consumed as the alkaline water moves through the reservoir.

Other ions including calcium and magnesium are also present on the surface of the clays. When the alkaline water contacts the clays, the calcium and magnesium ions will be exchanged for the sodium ions in the alkaline water. This reaction further consumes the caustic. Cooke et al (25) have shown that consumption of caustic by clay minerals increases as the pH of the alkaline water, the temperature and contact time are increased.

(b) Reaction of Sodium Hydroxide with Native Water.

Water native to an oil reservoir may contain a large amount of polyvalent ions. These ions will react with sodium hydroxide, forming precipitates. The precipitates are not only harmful in that caustic is consumed but they also create a permeability reduction in the reservoir, especially near the wellbores.

A typical analysis of a native brine shows the presence of:

Cations	Anions
Ca^{++}	SO_4^{--}
Mg^{++}	Cl^-
Na^+	NO_3^-
K^+	HCO_3^-

The ions which may react with sodium hydroxide (NaOH) in significant quantities are Ca^{++}, HCO_3^-, Mg^{++}. The reactions which may take place are:

(i) Dissociation of sodium hydroxide in water

$$NaOH \rightarrow Na^+ + OH^-$$

(ii) Reaction of polyvalent ions with the dissociated ions

$$HCO_3^- + OH^- \longrightarrow H_2O + CO_3^{--}$$
$$Mg^{++} + 2OH^- \longrightarrow Mg(OH)_2$$
$$Ca^{++} + 2OH^- \longrightarrow Ca(OH)_2$$

The extent of the above reactions depend on many variable conditions, some of which are the concentration of the caustic, concentration of the polyvalent ions and temperature at which the reactions occur. It would be extremely difficult to predict exactly how much sodium hydroxide is consumed by a particular ion even though the concentration of that ion is known.

D. Emulsions (12,16)

An emulsion is a forced mixture of two immiscible or incompletely miscible liquids -- for instance, oil and water. Fine droplets of one fluid become suspended in the other. If the emulsions are stable, the fluids will not separate unless treated with heat or a demulsifier.

Low interfacial tensions between two fluids facilitate the formation of an emulsion. Agitation of the liquids is usually required. However, if the interfacial tension is low enough and the conditions are ideal, spontaneous emulsification may occur.

Surface active agents are responsible for the lowering of interfacial tension, and hence are called emulsifying agents. The surface active agent is slightly soluble in one of the liquids and becomes adsorbed on its surface as a film. This will cause the lowering of the interfacial tension. The amount of adhesion between the liquids will be increased and a large interfacial area created between them. The surface is in the form of very small spheres, from 0.5 to 10 microns in diameter, as one liquid is dispersed in the other.

Previously (17), the interfacial tension was regarded as a very important factor in determining the stability and particle size of emulsions. It was thought that a high interfacial tension signifies a large input of energy to create new surfaces and hence

was unfavourable to emulsification. Therefore the fundamental advantage of emulsifiers was their ability to lower interfacial tension to form emulsions. It is certainly true that a low value of interfacial tension facilitates the disruption of bulk liquid interfaces. However, it is recognized now that the real importance of the emulsifier lies in the stabilization of the emulsions.

Emulsions (12) may be water-in-oil or oil-in-water. In the first case, the continuous phase is oil, with the fine water droplets dispersed through the oil. This type of emulsion may contain up to 90 percent water (18). These emulsions are stabilized by a film which encapsulates the water droplets and prevents them from coalescing. This film can be quite rigid and is generally thought to be associated with the asphaltic fraction of the crude. The second type, or oil-in-water emulsion, consists of water as the continuous phase and oil droplets are suspended in the water. These emulsions are stabilized by electric layers formed from the deposition of emulsifiers which are polar in nature at the liquid/liquid interface. The reaction between sodium hydroxide and the carboxylic acids in a crude oil may produce this type of emulsifier.

E. Simulation of Reservoir Saturation History and Conditions

The experimental conditions in this study will be designed to simulate the saturation history and reservoir conditions of the Wainwright Oilfield.

It has been shown that Restored Wettability Waterfloods on core packs (27) could be used to indicate whether oil production would be increased by alkaline waterflooding in a reservoir. This procedure combines crude oil, brine and sand in such a way as to simulate the saturation history of a reservoir. Clean, friable sand was crushed and put into core holders. These core packs were saturated with native water. Crude oil was then used to displace the native water to an irreducible saturation. The oil-saturated sand packs were then allowed to age for 1000 hrs (27), at which time no further wetting change occurred and reservoir wettability was approximated. The cores were then ready for waterflood tests.

The Wainwright Oilfield is presently being flooded with water and about 0.24 pore volume of water has been injected so far. To simulate the injection of caustic at this time in the field, a slug of 0.24 pore volume source water is usually injected before the caustic slug in an aged core pack. The size of the caustic slug for the core is determined to be 0.17 pore volume which is economically feasible for field application. The magnitude of this number was determined by an oil company operating in the heavy oil producing areas of Alberta. All the floods in the laboratory are conducted at the reservoir temperature of 26.6 ^{o}C.

EXPERIMENTAL EQUIPMENT

A. Spinning Drop Apparatus For Measuring The Interfacial Tension Between Two Liquids

The spinning drop apparatus as described by McCaffery (28) consists of a cell in the form of a cylindrical tube having a volume of 1 cc approximately. The tube was made of Pyrex and held horizontally. One end of the cell was closed while the open end was sealed by a silicone rubber septum. The tube was filled with the denser aqueous phase and made to rotate on its axis at a known RPM. An oil droplet of a few microlitres in volume was introduced into the tube. When the cell was rotated, the oil droplet elongated along the axis of rotation, reflecting a balance between the interfacial tension and centrifugal force. The dimensions of the elongated drop, measured on the X and Y axis, were used to calculate the interfacial tension.

B. Saturation and Displacement Apparatus

Fig 1 shows the apparatus which, with suitable modification, was used for either saturating or displacing the core packs with appropriate fluids.

The displacement pump was a constant injection rate pump which used mercury as the displacement fluid. Mercury was injected into either one of the three stainless steel cylinders containing different fluids. Pump capacity was from 2.5 cc/hr to 1121 cc/hr.

SCHEMATIC DIAGRAM OF EXPERIMENTAL APPARATUS.

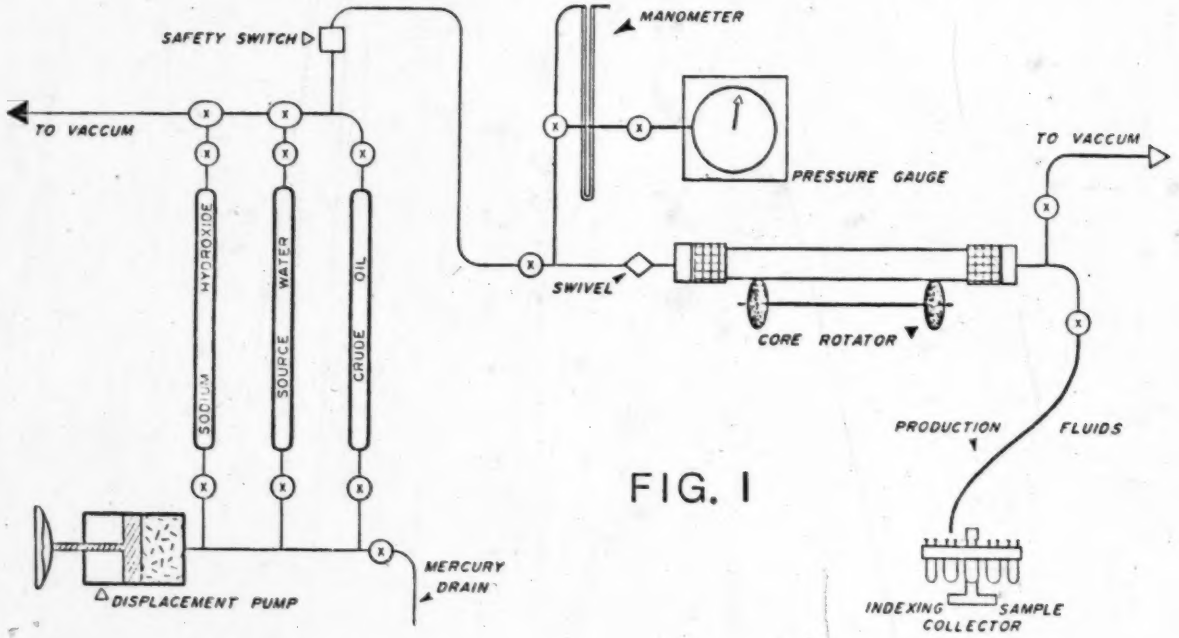


FIG. I

The line connecting the stainless steel cylinders and the pump was 1/8 inch stainless steel tubing. All the lines upstream of the cylinders were 1/4 inch stainless steel tubing.

The steel cylinders were 97.47 cm long, 4.95 cm I.D. and held approximately 3.6 litres. The valves upstream of the cylinder were fitted with rupturing discs which would withold a pressure of 1900 psig. They served as pressure relief valves for the system.

The upstream end of these cylinders was hooked up to a vacuum pump and also to the core pack via a safety switch. The vacuum pump enabled the fluids in the cylinders to be deaerated. The safety switch would cause the displacement pump to be shut off automatically should the mercury reach that point.

A mercury manometer and a Heise pressure gauge were used to measure the pressure differential across the core pack.

The core pack consisted of a stainless steel cylindrical tube, 108 cm in length, and two end caps. The diameter of the tubes used was either 3.81 cm (1.5 ins.) or 5.08 cm (2 ins.). The cylindrical tube was filled with sand and the end caps were then screwed on. Fine mesh steel screens were secured on the inside of the end caps to prevent sand fines from being produced along with the fluids. There were nipples on the end caps so that the core pack might be connected to the rest of the system. The core pack

was placed on a core-rotator which was driven by a 1/2 h.p. electric motor. The rotator travelled at a speed of 1 revolution per hour. This was used to prevent the segregation of different fluids in the core pack due to their different densities. The swivel at the upstream side of the core packs allowed the system to be freely rotated.

The downstream side of the core pack was connected to the vacuum pump and also the indexing sample collector. When a dry core was being saturated with a fluid (usually water), the core pack was first evacuated with the vacuum pump. When a saturated core was being displaced with another liquid, the produced fluids were collected in centrifuge tubes.

Each tube had a capacity of 50 mls and was automatically advanced to the producing outlet of the core pack by the collector. The collector held up to 24 centrifuge tubes at one time. An International Centrifuge was used to separate the production fluids in the centrifuge tubes.

C. Other Equipment

(a) Cannon Fenske viscometers were used for measuring the viscosities of the different crude oils in a constant temperature water bath.

(b) An Orion Research pH Meter was used to measure the pH of different solutions.

EXPERIMENTAL PROCEDURE

A. Source and Handling of Materials

Three types of sand particles were used to make up the core packs:

i) clean Sundance Kinsella Sand

ii) Shaly Sundance Kinsella Sand

iii) Saskatchewan heavy oil reservoir sand

The first two types of sand were obtained from a consolidated core sample cored from a producing well in the Wainwright Oilfield. The third type of sand was obtained from an unconsolidated core sample of a Saskatchewan heavy oil reservoir. All the core samples were crushed and ground up separately in a grinder into sand particles, then put into a core cleaning apparatus and soaked in toluene until all the crude oil had been removed from the sand surfaces. Steam was then passed through the sand until it was cleaned of toluene. An oven was used to bake the sand at 260 ^{o}C until all traces of toluene were evaporated.

After the sand had been steamed and dried, it was passed through a series of sieves. Particles deemed not suitable in size for the purpose of the displacement tests were discarded. An analysis of the particle sizes for each sand is included in Appendix A.

Core #1, 2, 3, 9 were packed with sand (i) while core #4, 5, 6 were packed with sand (ii) and sand (iii) was packed into core #7, 8 and 10.

B. Measurement of Fluid Properties

(a) Water - Two types of water were used in this project:

(i) Native water - Water produced from the Wainwright oil field in association with the oil (connate water).

(ii) Source Water - Water from source wells in the Wainwright oil field for use as injection water.

The different ion concentrations in these two types of water were analyzed. Other properties such as ignition loss, solid content and alkalinity were also determined. This complete water analysis was performed by the Alberta Department of Agriculture. The du Nouy ring tensiometer was used to measure the surface tensions of both types of water. The densities of the water were determined at different temperatures using standard specific gravity bottles. Viscosity of the native water was measured by Cannon-Fenske viscometer.

(b) Crude Oil

The crude oil obtained from the field contained a certain amount of water. This water was completely removed by heat in a

crude dryer. Any light ends which came off along with the water were blended with the dried crude again.

The viscosity and density of the crude at 23 ^{o}C (room temperature) and 26.6 ^{o}C (reservoir temperature) were determined by a Cannon-Fenske viscometer and standard specific gravity bottles respectively. The surface tension of the dry crude was obtained by using the du Nouy ring tensiometer. Other properties of the crude oil such as acid number and asphaltene number were also determined.

The dry crude had a very high viscosity. In order to simulate the actual crude oil viscosity in the reservoir, n-heptane was added to the crude until its viscosity had been reduced to 74 cp at 26.6 ^{o}C.

(c) Sodium hydroxide solutions - Sodium hydroxide solutions were made up at different concentrations with reagent grade solid sodium hydroxide. The concentration of the solutions was standardized against hydrochloric acid of known concentration.

C. Core Packing

Sand was packed into the core holder through the open end. A plastic mallet was used against the sides of the core holder until the sand settled. The core was vibrated with air vibrators until the sand did not settle appreciably, sand being added to keep

the level constant. This compaction usually took 72 hours. The top end cap was then fastened on to the open end. In an attempt to obtain uniform properties in different core packs identical packing procedures were used in each core pack.

D. Measurement of Core Properties

The core pack was first evacuated of all air by means of a vacuum pump. A manometer was used to indicate how well the vacuum was maintained.

(a) Pore volume - The pore volume of the core pack was measured by two different methods.

i) Volumetric method - An evacuated core pack was suspended vertically and native water injected through the lower end cap. The effluent water was collected in a graduated flask. The injection rate of the pump was adjusted so that a constant pressure differential existed across the core pack. When the rate of injection of water was the same as the rate of production, the pump was shut off. The difference between the total volume of water injected and that produced should be equal to that in the core. This amount of water was the pore volume.

ii) Weight method - The evacuated core was weighed before water injection and also afterwards. By knowing the

density of the water, the pore volume of the core can be calculated by knowing the weight of water in the core.

(b) Porosity - The bulk volume of the sand in the core was calculated from the dimensions of the core holder and the end caps. Knowing the pore volume and the bulk volume the porosity was calculated.

(c) Absolute Permeability - After the porosity had been determined, the core was saturated with water. Native water was injected into the core horizontally at a constant rate and the pressure differential across the core monitored. Darcy's linear flow equation was used to calculate the absolute permeability to water.

(d) Irreducible Water Saturation - When the absolute permeability had been determined, the core was suspended vertically. Crude oil was then injected vertically down through the core pack, and the effluent collected in centrifuge tubes. Varsol was added to the effluent and the tubes were centrifuged to separate the water and the oil. When a negligible amount of water (0.5 ml water for 40 ml of oil) came out, the core was at a simulated irreducible water saturation.

E. Aging of Core Packs

The core was then ready for aging. It was put on a core

rotator which rotated at approximately 1 revolution per hour. The core was kept on this rotator for 1000 hours or more before displacement tests were performed.

F. Consumption of Sodium Hydroxide

Sodium hydroxide, in solution form, will react with sand, native and source water. To find out how much caustic would actually react, the following tests were performed.

(a) Source Water - A sample of source water was weighed out in a beaker. A certain volume of sodium hydroxide of known concentration was transferred by means of a pipette into the beaker. The resulting mixture was stirred and titrated against hydrochloric acid to find the residual amount of sodium hydroxide.

(b) Native Water - The above procedure was repeated for a sample of native water.

(c) Consumption by Sand - Sundance Kinsella sand used for cores #4, 5, 6 was used for this study. Five samples of Sundance Kinsella sand of 100 gm each were put into separate beakers. Sodium hydroxide solutions of different concentrations were added to the beakers. The amount of solution added was 100 ml each. The mixture of sand and solution was stirred and the clear solution was titrated for concentration of sodium hydroxide. The experiment

was performed at 26.6 ^{o}C. Titrations were performed at different intervals afterwards.

B. Interfacial Tension

Two sets of interfacial tension data were obtained using the spinning drop apparatus. One set of data was obtained by using dry Wainwright crude oil and solutions of sodium hydroxide at different concentrations in source water. The second set of data was obtained by using dry Wainwright crude oil diluted with n-heptane instead of the more viscous dry crude.

Densities of the oil and the sodium hydroxide solutions were measured and calculations of the interfacial tension between the sodium hydroxide and crude oils were made.

H. Emulsion Formation and Behavior

Emulsions were deliberately created in the laboratory using sodium hydroxide and the two different types of crude oil, dry crude and dry crude diluted with n-heptane.

One hundred ml of sodium hydroxide solution of known concentration was placed in a blender with 100 ml of dry crude oil. The blender was turned on for one minute, then stopped for another minute. Three minutes of blending time were used, with one minute

rest interval between each minute. At the end of the blending, the emulsions were put into a separatory funnel and allowed to stand for an hour. For the emulsions which separated into an aqueous phase and a denser phase, a sample from each was taken. The samples were put under a microscope and photographed. Different concentrations of sodium hydroxide were used to obtain six samples of emulsions.

The above procedure was repeated for the dry Wainwright crude diluted with heptane. The same concentrations of sodium hydroxide were used in both cases, ie 0,2,4,6,8 and 10 wt %.

After the emulsions had been allowed to stand for 1 hour, some separated into two phases. One phase was viscous, the other was more aqueous and much less viscous. A sample of known volume was taken from each phase and dissolved in toluene. The mixture was distilled until the oil and water had separated completely. The percentage of oil and water in each phase was calculated.

For the emulsions which did not separate into two phases, a known amount of sample was also taken and distilled to find out the percentage composition of oil and water.

The aqueous phases of the emulsions were titrated for residual amount of sodium hydroxide left. For the emulsions which did not separate, titrations were not possible.

I. Displacement Tests

Two types of displacement tests were performed on the aged cores.

(a) Source Water Floods - Source water was injected into the cores to displace the oil. The production of oil and water from these floods served as a standard for the sodium hydroxide floods.

(b) Sodium Hydroxide Floods - After a source water flood had been performed, the core was resaturated with native water. Crude oil was used to displace the native water so that an irreducible water saturation was obtained. The core was then ready for a sodium hydroxide flood. A 0.24 pore volume of source water was injected into the core, followed by a 0.17 pore volume of sodium hydroxide at a particular concentration. The injection rate was the same as that in the source water flood. After the injection of the sodium hydroxide slug, the flood was continued with source water until a cumulative total of approximately 1.8 pore volume fluid had been injected.

The production water and oil in all floods were collected and separated by centrifuge and varsol. The volumes of both liquids were recorded. The pH of the effluent water was determined by a digital pH meter while the chloride ion concentration was found by titrating with silver nitrate.

In this study, cores of 1½" and 2" diameters were used. For the two inch cores the flooding procedures and sequence as described above were followed quite closely. For the 1½" cores, procedures were altered in specific floods so that emulsions, the same as those produced from 2" cores, might be obtained. These variations included using dry crude without n-heptane for saturating cores, continuous injection of sodium hydroxide treated water or injecting sodium hydroxide solution at a high rate.

Table 1 summarizes the conditions under which floods were performed on each core. The injection rate for floods on the 2" core was constant at 20 cc/hr. while that for the 1½" cores was different for different runs. In some cases a plain waterflood was not conducted.

TABLE 1

SUMMARY OF THE CONDITIONS FOR EACH DISPLACEMENT TEST

	PLAIN SOURCE WATERFLOOD				SODIUM HYDROXIDE FLOOD					
Core Number	Core Size	Run No.	Rate (cc/hr)	Crude Oil Used	Run No.	Initial Water Flood (Pore Volume)	Rate (cc/hr)	Slug Size (Pore Volume)	Concentration (wt. %)	Crude Oil Used
1	2"	1	20	#1	12	0.24	20	0.17	2.0	#1
2	2"	2	20	#1	13	0.24	20	0.17	4.0	#1
3	2"	3	20	#1	14	0.24	20	0.17	8.0	#1
4	1½"	5	12	#1	16	0.24	12	0.17	6.0	#1
5	1½"	6	12	#1	-	-	-	-	-	-
		7	12	#1	-	-	-	-	-	-
		9	50	#1	19	0.24	50	0.17	6.0	#1
6	1½"	8	12	#1	17	0.24	12	0.17	6.0	#1
		-	-		18	-	20	1.82	6.0	#1
7	1½"	10	12	#1	-	-	-	-	-	#1
		11	12	#2	21	0.24	12	0.17	6.0	#2
8	1½"	-	-	-	20	0.24	12	0.17	6.0	#1
9	2"	-	-	-	15	0.24	20	0.17	6.0	1
10	1½"	-	-	-	22	-	2.5	0.17	6.0	#1

* Crude Oils Used

#1 - Dry Crude Diluted with Heptane to 104 cp at 70 ^{o}F

#2 - Dry Crude with no n-heptane

EXPERIMENTAL RESULTS AND OBSERVATION

A. Sand and Fluid Properties

Appendix A details the analyses of the sand and fluids used in the experiments.

(a) Sand Properties

The mean mass diameter and median diameter of the three types of sand grains were calculated from screen analyses. A size distribution chart comparing the different sands is shown in Fig A-1, Appendix A.

Sand packed in the 2" cores (#1,2,3,9) had a porosity (Ø) ranging from 42.5% - 44.2% and absolute permeability K of 243 - 457 md.

Sand used for the 1½" cores (#4,5,6) had a porosity ranging from 45 - 46% with an absolute permeability of 209.16 md - 260.5 md.

Sand packed in cores #7,8 had a porosity of 38.7% and permeability of 1.53 - 1.55 Darcys. This sand came from the same formation as core #10 which had a porosity of 40.19% and an absolute permeability of 62.9 md. The large discrepancy in the permeabilities existed because the sand came from different sections of the same core.

An X-ray diffraction of the sand used for packing the cores was performed. However, no definite sand composition was established because it was extremely difficult to determine the percentage of clays present in the sample. A chemical analysis of sand used for cores #1,2,3,9 is shown in Table A-2, Appendix A. The main component is silicon dioxide SiO_2. Oxides of aluminum and iron are also present, together with traces of calcium and magnesium.

(b) Fluid Properties

Table A-3 shows the chemical composition of both the source and native water. The analysis was performed by the Alberta Agriculture Department. It may be seen that the native water contained a large amount of polyvalent ions, much more than the source water.

Table A-4 in Appendix A shows the properties of the crude oil used. The crude oil as received from the field contained 6% by weight of water and its viscosity was 205 cp at 23 ^{o}C. After drying, the viscosity became 992 cp at 23 ^{o}C. When diluted with n-heptane the viscosity was 104 cp at 23 ^{o}C (room temperature) and 74 cp at 26.6 ^{o}C (reservoir temperature).

B. Consumption of Sodium Hydroxide

Source water did not react strongly with sodium hydroxide.

Precipitation of insoluble salts did not occur when the two were mixed in a beaker at 26.6 ^{o}C. Titration results showed that source water did not consume any appreciable quantity of sodium hydroxide.

On adding sodium hydroxide solution to native water, a white precipitate was formed immediately. Heat was also generated as shown by the fact that the mixture became warm. Titration results showed that 100 gm of native water consumed approximately 0.6 gm of solid reagent grade sodium hydroxide. In Appendix B, a theoretical calculation, to predict whether a precipitate would be formed when a specific concentration of sodium hydroxide was added to a sample of water containing polyvalent ions, is shown.

It is very difficult to predict how much sodium hydroxide will be consumed by each individual ion in the water. Different ions will react at a different rate and to a different degree with the sodium hydroxide. The different reactions and the products formed will interfere with each other, making the calculations very complex.

Sand did not react appreciably with sodium hydroxide when the two were mixed in a beaker. Results are shown in Appendix B, Table B-1. However, it was interesting to observe that after a sodium hydroxide flood had been carried out on a core and the core was being resaturated with native water, the pH of the effluent

would not decrease to that of the native water, even after 3 pore volumes of native water had been injected. This phenomenon was observed in core #6 and indicated a certain amount of sodium hydroxide had been trapped in the porous medium, possibly adsorbed on the surfaces of the sand grains. As more water was passed through the core, the caustic was washed off the sand grains gradually and entrained in the native water.

C. Core Properties and Initial Conditions for Each Run

Table C-1 in Appendix C shows the physical properties of each core pack such as porosity $\emptyset$, absolute permeability K and pore volume. The properties of core packs made up of the same sand were quite similar, with the exception of cores #7,8,10. Core #10 was made from the same sand as cores #7,8. However, a different section of the core sample from which the sand was obtained, was used for core #10 and this section has more fine particles.

In addition, the dry packing technique used in packing the core packs may not have produced core packs with identical properties even though they were made of the same sand. As a result core #7 and core #8 had an absolute permeability of 1.55 and 1.53 darcys respectively, while core #10 had a permeability of only 62.9 md. The porosity of core #10 was also higher. Table C-2 shows the initial conditions of the cores for each run.

D. Interfacial Tension

The interfacial tension data between sodium hydroxide and dry Wainwright crude, as well as sodium hydroxide and dry Wainwright crude diluted with n-heptane are shown in Fig 2.

The exact value of the minimum interfacial tension between sodium hydroxide and the dry crude was very hard to obtain because the oil droplet became very unstable in the spinning drop apparatus at low concentrations of sodium hydroxide (0.1 - 1%).

It may be seen from Fig 2 that the general shape of the two interfacial tension vs. sodium hydroxide concentration curves is very similar. The two crude oils may even have similar minimum interfacial tensions at the same sodium hydroxide concentration, judging from the shape of the curves.

N-heptane did not react appreciably with the crude oil in this case to influence the interfacial properties of the dried crude.

E. Formation of Emulsions

Two types of emulsions were obtained, one from sodium hydroxide and dry crude, the other from sodium hydroxide and dry crude diluted with n-heptane. There was a distinctive difference between the two types of emulsions in the oil phase.

RELATIONSHIP BETWEEN INTERFACIAL TENSION AND SODIUM HYDROXIDE SOLUTIONS IN SOURCE WATER

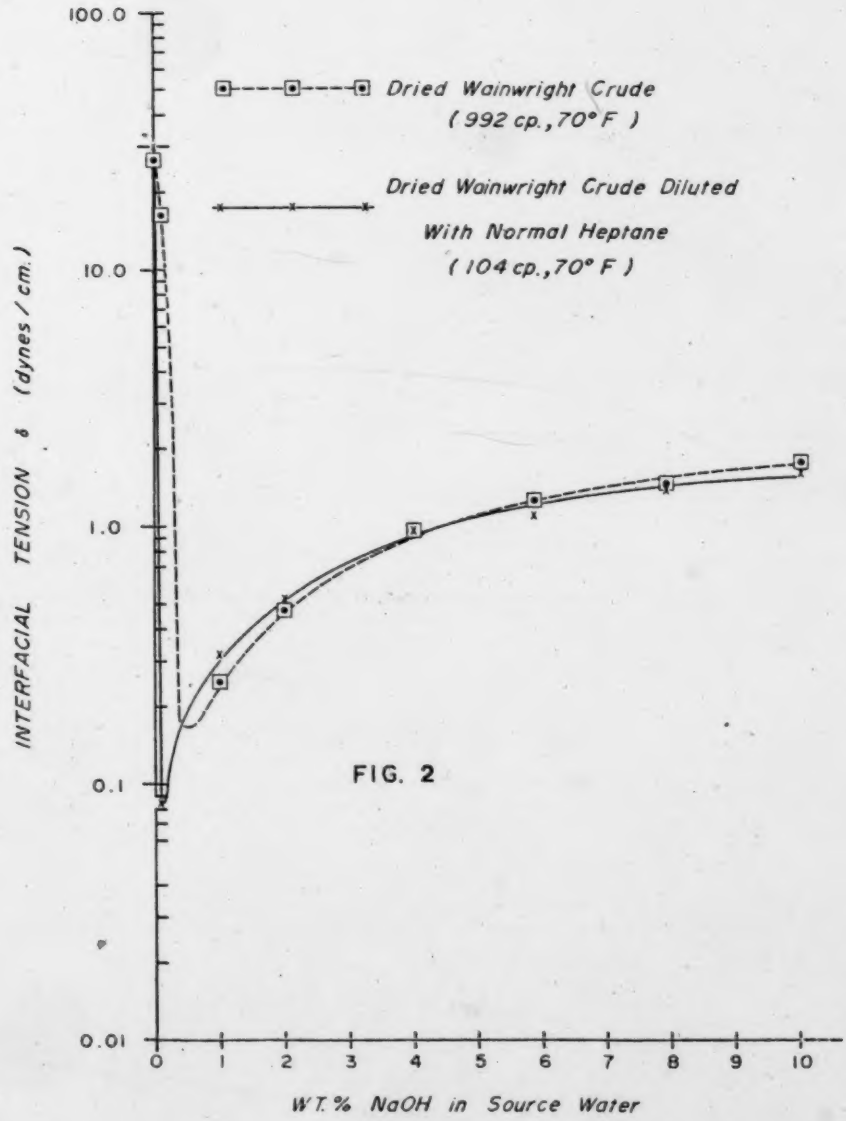


FIG. 2

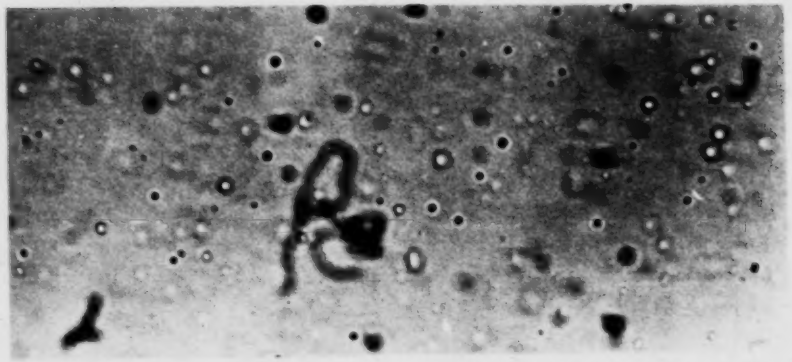
After the emulsions had been prepared as described earlier, they were left standing to be separated into a more mobile aqueous phase and a viscous immobile oil phase. Samples from each were taken, put under a microscope and photographed. Figs 3 - 5 show a comparison of the aqueous phase of the two types of emulsions made with the same concentration of sodium hydroxide.

From the photos, it may be seen that oil droplets were suspended in the aqueous phase in all of the emulsions, whether dry crude or diluted dry crude was used, and at all concentrations of sodium hydroxide used.

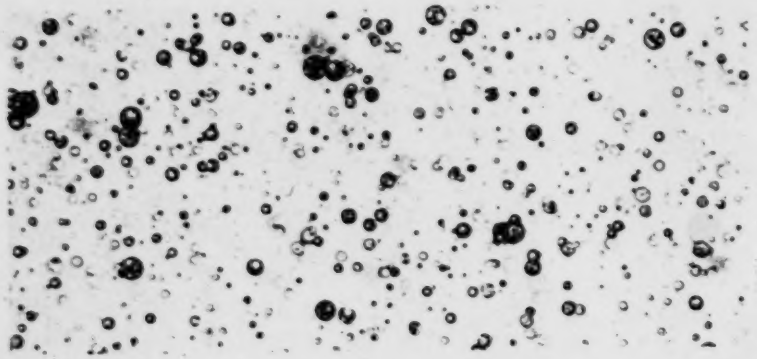
When the emulsions were being prepared it was found that in all cases the dry crude diluted with n-heptane yielded a much more viscous type of emulsion than the undiluted dry crude. All emulsions formed from the undiluted crude separated into an oil phase and water phase. Only one of the emulsions from the diluted crude separated into an oil phase and water phase. The emulsions made with diluted crude were so viscous that they would not flow.

Figs 6-8 show a comparison of the oil phase of the two types of emulsions made with different crudes but the same concentration of sodium hydroxide. It may be seen that water droplets are suspended in the oil phase of the dry crude emulsions. The texture of the diluted - crude emulsions however was different. Even at a higher magnification (1750X) no large discernible water

(a) Source Water(0% NaOH) and Dry Crude 1750x



(b) 2% NaOH and Dry Crude 710x



(c) 2% NaOH and Dry Crude + Heptane 1750x

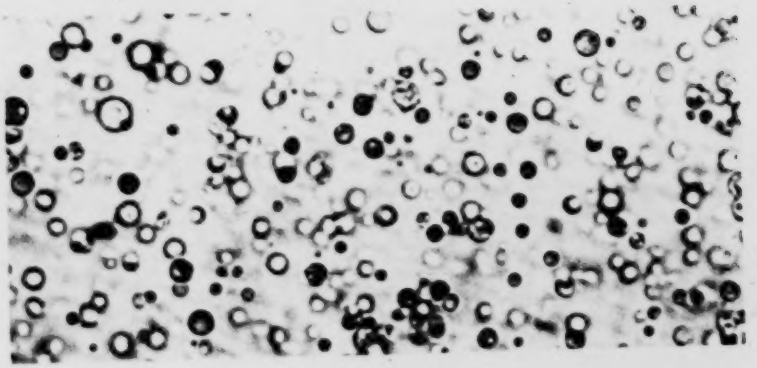
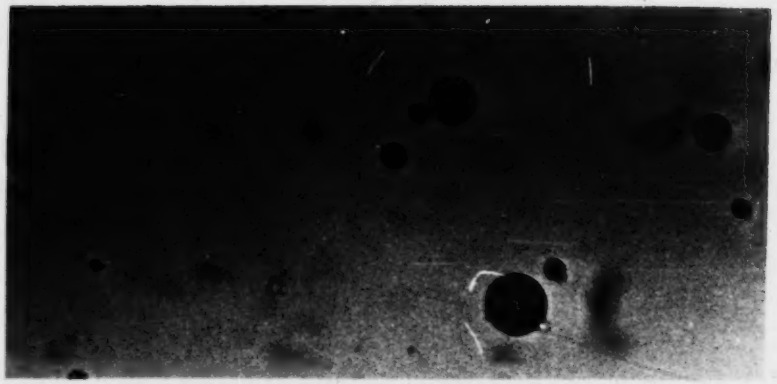
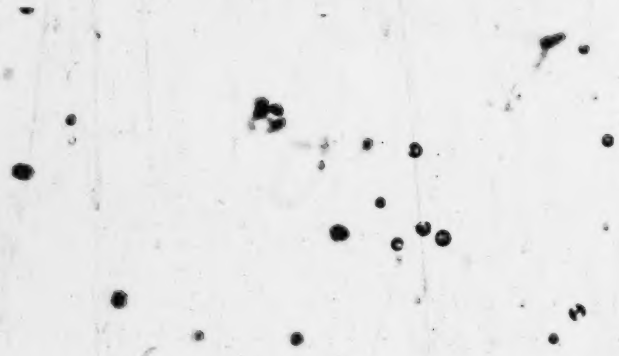


Fig.3 Water Phase Emulsions from (i) dry Wainwright Crude and NaOH solutions

(ii) Dry Wainwright crude +Heptane and NaOH Solns.



(a) 4% NaOH and Dry Crude (710x)



(b) 4% NaOH and Dry Crude + Heptane 1750x

(c) 6% NaOH and Dry Crude (710x)

Fig 4 Water Phase Emulsions from (i) Dry Wainwright Crude and NaOH Solutions

(ii) Dry Wainwright Crude + Heptane and NaOH Solutions

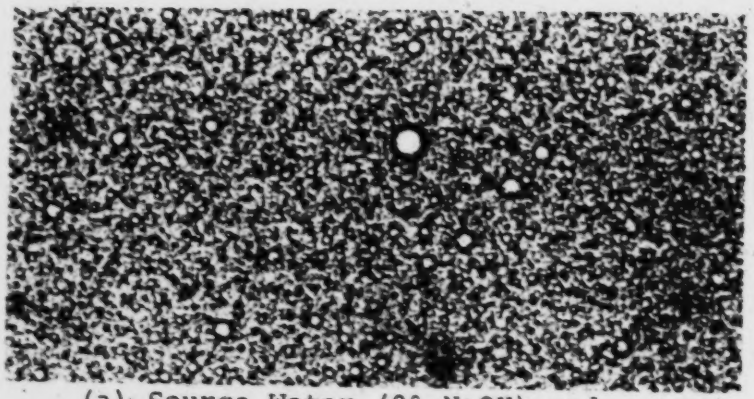
(a) 8% NaOH and Dry Crude (710x)

(b) 10% NaOH and Dry Crude (710x)

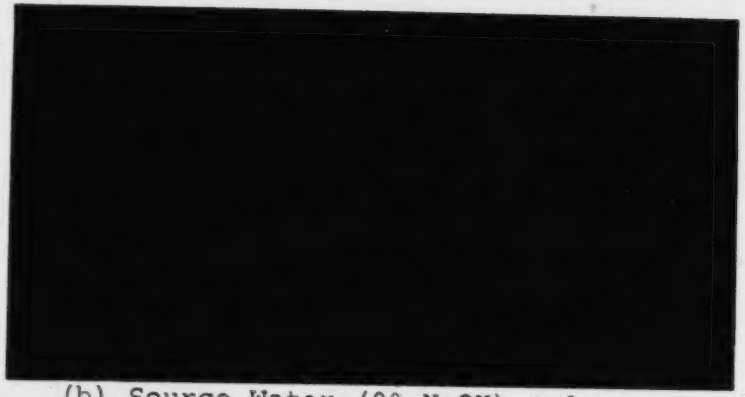
(c) 10% NaOH and Dry Crude + Heptane (710x)

Fig 5 Water Phase Emulsions from (i) Dry Wainwright Crude and NaOH Solutions

(ii) Dry Wainwright Crude + Heptane and NaOH Solutions

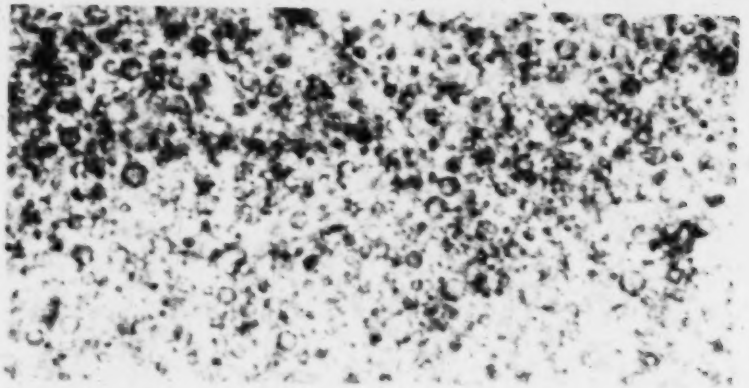


(a) Source Water (0% NaOH) and Dry Crude (710x)



(b) Source Water (0% NaOH) and Dry Crude + Heptane (1750x)

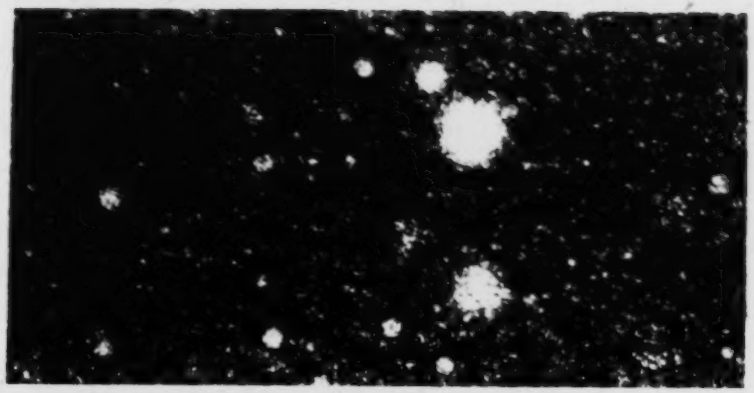
(c) 2% NaOH and Dry Crude (710x)



(d) 2% NaOH and Dry Crude + Heptane (1750x)

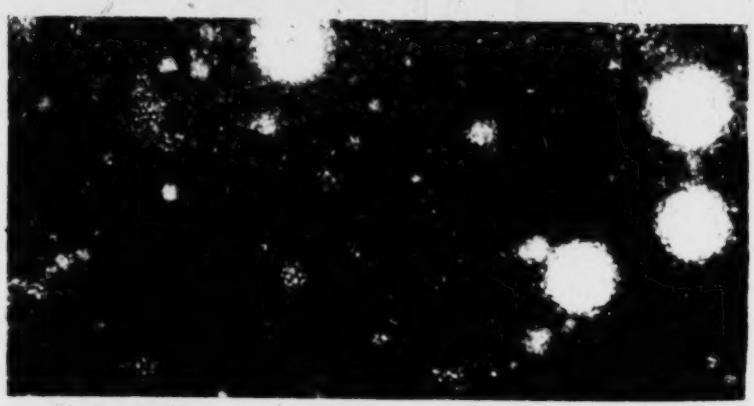
Fig 6 Oil Phase Emulsions from (i) Dry Wainwright Crude and NaOH Solutions

(ii) Dry Wainwright Crude + Heptane and NaOH Solutions

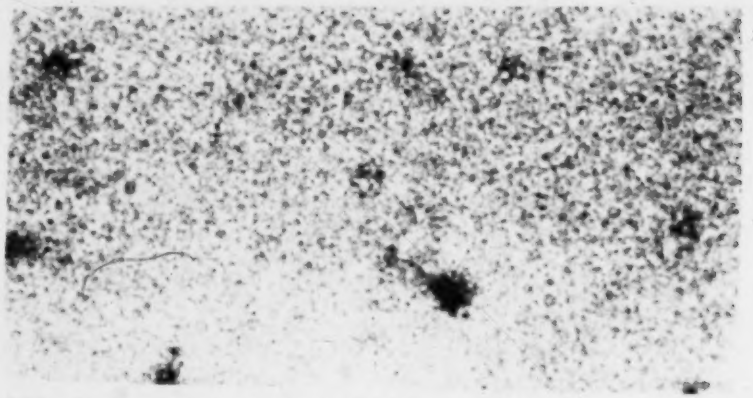


(a) 4% NaOH and Dry Crude (710x)

(b) 4% NaOH and Dry Crude + Heptane (1750x)



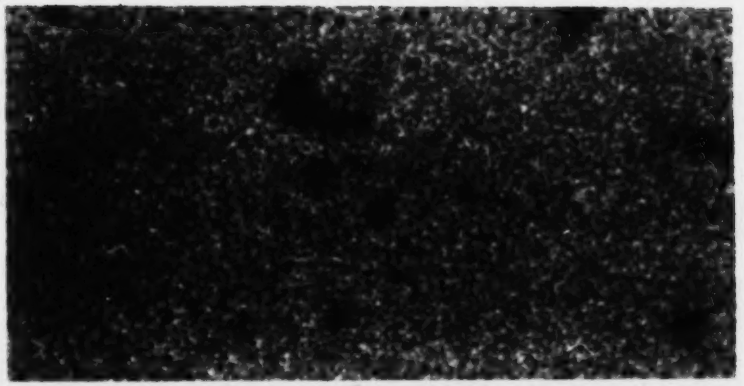
(c) 6% NaOH and Dry Crude (710x)



(d) 6% NaOH and Dry Crude + Heptane (1750x)

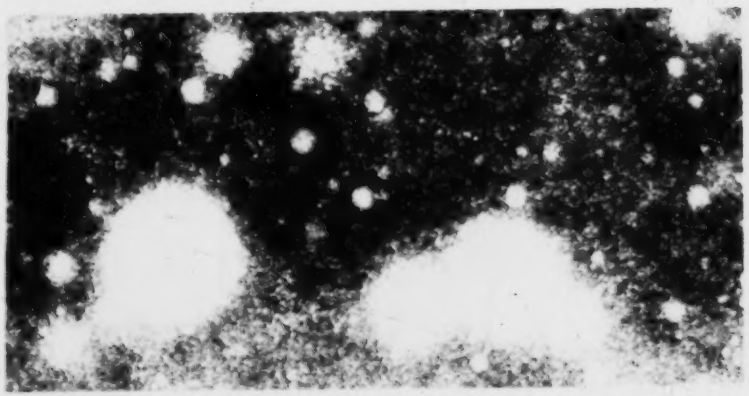
Fig 7 Oil Phase Emulsions from (i) Dry Wainwright Crude and NaOH Solutions

(ii) Dry Wainwright Crude + Heptane and NaOH Solutions



(a) 8% NaOH and Dry Crude (710x)

(b) 8% NaOH and Dry Crude + Heptane (1750x)



(c) 10% NaOH and Dry Crude (710x)

(d) 10% NaOH and Dry Crude + Heptane (1750x)

Fig 8 Oil Phase Emulsions from (i) Dry Wainwright Crude and NaOH Solutions

(ii) Dry Wainwright Crude + Heptane and NaOH Solutions

droplets may be found except in Fig 6d where 2% NaOH had been used. The diluted crude emulsions had an uniform and almost homogeneous texture.

The water phase and oil phase from these two types of emulsions were distilled in order that their composition be determined. Tables 2 and 3 show the results obtained. The water phase had a large percentage of water and oil droplets and hence was classified as oil-in-water emulsion. The viscous phase was classified as water-in-oil emulsion.

In Table 2 it is shown that the water phase of the undiluted-crude emulsions contained from 95 - 97% water depending on the concentration of sodium hydroxide. The viscous phase contained 13 - 43% water. The residual sodium hydroxide concentration in the water phase was determined and approximately 10% of the original concentration was present.

In Table 3 it is shown that for the diluted-crude emulsions, the water constituted 36-60% of the volume of the emulsions.

F. Displacement Tests

(a) Source Waterfloods

Results of the waterfloods on the 2" and 1½" diameter cores

TABLE 2

ANALYSIS OF EMULSIONS FORMED BETWEEN SODIUM HYDROXIDE IN SOURCE WATER AND DRY CRUDE

Sample #	Emulsion Constituents				Water Phase Used For Distilling (cc)	Water Distilled Out (cc)	% Water in Oil-in-Water Emulsion	Oil Phase Used (cc)	Water Distilled Out of Emulsion (cc)	% Water in Water-in-oil Emulsion	Remarks	% NaOH Consumed
	Amt Oil (cc)	Amt H_2O (cc)	Con. NaOH (wt. %)	Amt NaOH (cc)								
1	50	50	-				95%			14%	Dark Colour	
2	200	200	2%	20	50	48.4	97%	50	6.4	13%	Dark Colour	91%
3	100	100	4%	10	35	33.2	95%	38	14.0	37%	Brown Colour	90%
4	100	100	6%	10				51	22.0	43%	Will not separate into 2 phases	
5	100	100	8%	10	26	25.3	97%	25	8.8	36%		91%
6	100	100	10%	10				35	13.5	39%	1 phase Only	91%
7	100	100	1%	10	20	19.2	96%	29	9.5	33%		

TABLE 3

ANALYSIS OF EMULSIONS FORMED BETWEEN SODIUM HYDROXIDE IN SOURCE WATER AND DRY CRUDE DILUTED WITH N-HEPTANE

Concentration of NaOH (wt %)	Wt % of Water in Viscous Phase (from Distillation)	Remarks
0	40	1 Phase
2	36	2 Phase
4	60	Viscous, one phase emulsions, free water droplets
6	45	Very viscous, one phase emulsion
8	49	Gel like emulsion (1 phase)
10	55	In the form of gel, will not flow, free water droplets

will be presented in this section. The performance of the floods will be discussed in terms of oil recovery, pH and chloride ion concentration of the effluent, pressure drop across the cores, and the producing water - to - oil ratio. These waterflood results will serve as a standard for the caustic floods.

1) Waterfloods on 2" cores

A total of three waterfloods were performed on 2" cores (Run #1,2,3). Run No. 1 is representative of all three runs and will be discussed in detail here. Results of the other runs are included in Appendix D in the form of tables and/or figures. It should be pointed out here that the dry packing technique used in packing the cores did not produce identical initial conditions in each core. As a result, there were some slight variations in the amount of oil recovered at water breakthrough and at the termination of the flood in waterfloods on different cores.

Figure 9 illustrates that the recovery of oil from core #1 was 45% of the initial oil in place at 1.5 cumulative pore volume of water injection.

The pH of the native water originally in the core was approximately 7.5 and that of the injected source water 8.8. However, the initial water production had a pH of 5.7, lower than any of these. The pH of the produced fluids increased

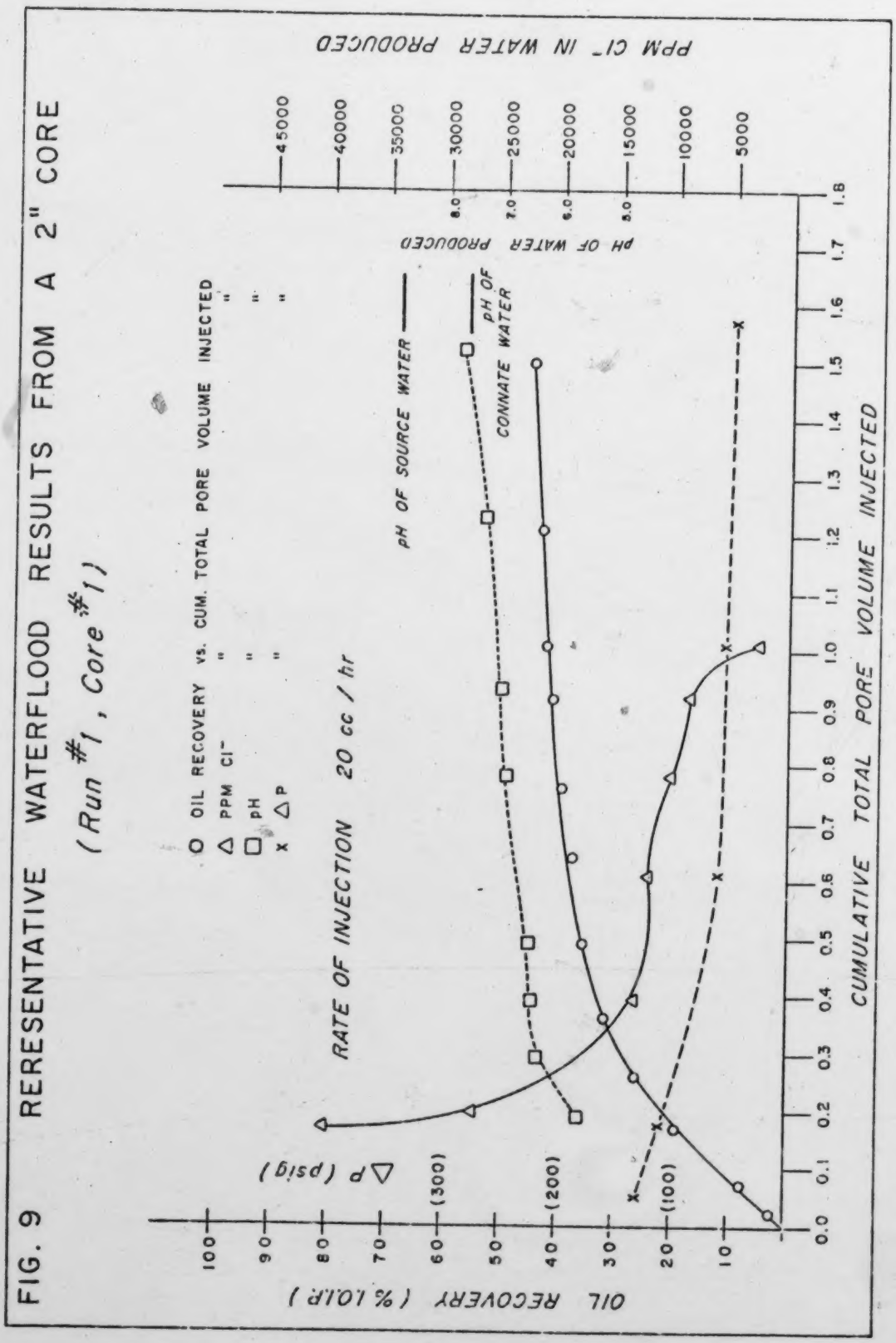

OIL RECOVERY (% OIL)
ΔP (psig)
CUMULATIVE TOTAL PORE VOLUME INJECTED
PPM Cl⁻ IN WATER PRODUCED
pH OF WATER PRODUCED
pH OF SOURCE WATER
pH OF CONNATE WATER
RATE OF INJECTION 20 cc / hr
O OIL RECOVERY VS. CUM. TOTAL PORE VOLUME INJECTED
△ PPM Cl⁻ "
□ pH "
X ΔP "

FIG. 9 RERESENTATIVE WATERFLOOD RESULTS FROM A 2" CORE (Run #1, Core #1)

steadily as the injection was continued. During the later part of the flood the pH of the effluent was similar to that of the connate water.

The chloride ion concentration of the effluent at initial water production was 40,000 ppm. The native water originally present in the core had a chloride ion concentration of 46,000 ppm while the injected source water only had 236 ppm. This showed that the initial production of water was mainly native water. The source water must have displaced some of the native water ahead of itself. During the displacement process, clean oil was produced first, followed by native water and oil, and then a mixture of native and source water and oil. As injection continued, the chloride ion concentration of the effluent dropped off rapidly, indicating all the contacted native water had been displaced out of the core.

The rate of injection into the 2" cores was constant at 20 cc/hr. There was a corresponding pressure drop across the core at this rate. As injection continued, this pressure drop decreased steadily until the end of the flood when it was nearly constant.

Figure 10 shows that the producing water-to-oil ratio of the effluent increased steadily from the moment of initial water production to the end of the flood.

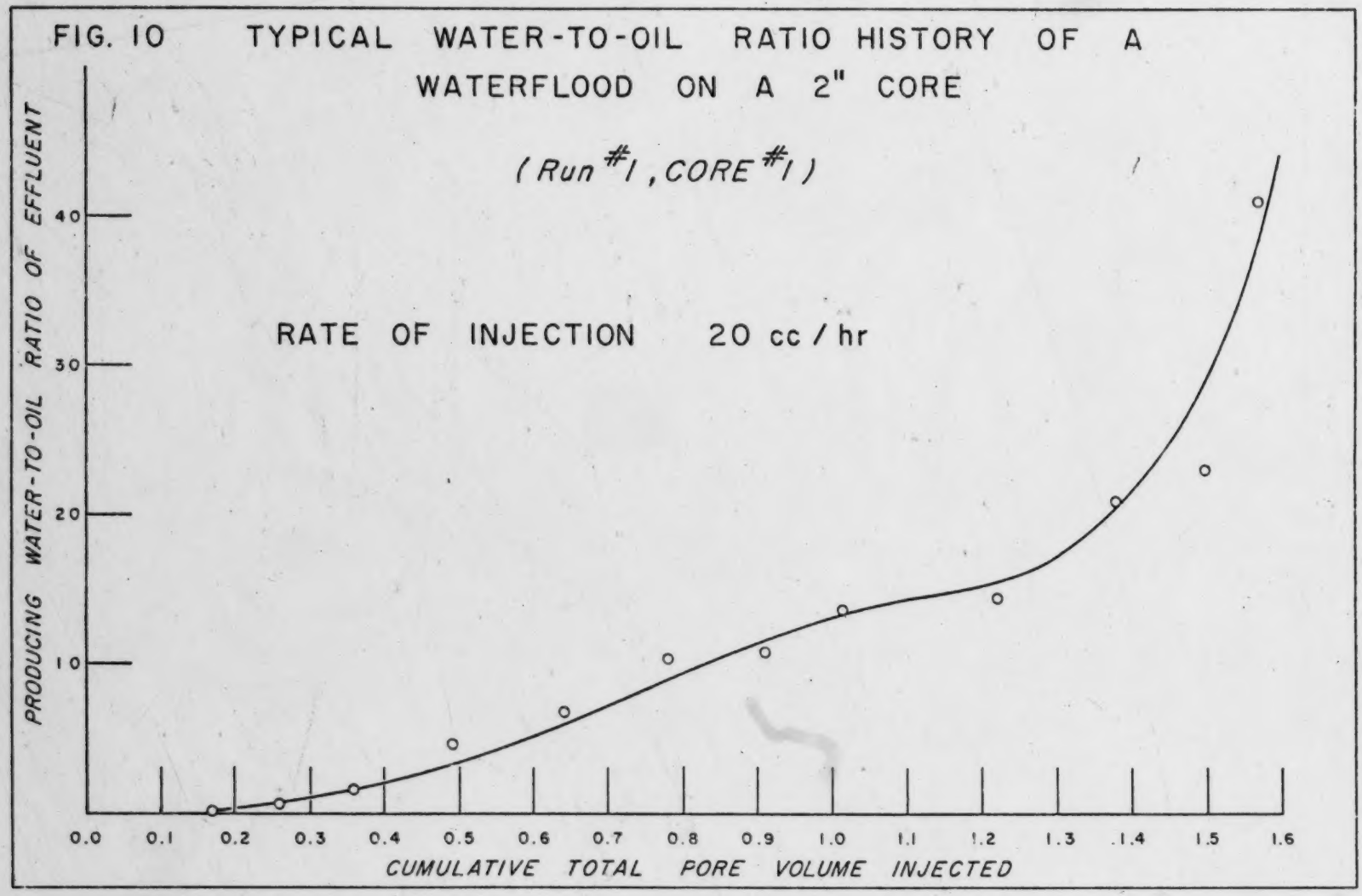


FIG. 10 TYPICAL WATER-TO-OIL RATIO HISTORY OF A WATERFLOOD ON A 2" CORE
(Run #1, CORE #1)
RATE OF INJECTION 20 cc / hr
PRODUCING WATER-TO-OIL RATIO OF EFFLUENT
40
30
20
10
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
1.1
1.2
1.3
1.4
1.5
1.6
CUMULATIVE TOTAL PORE VOLUME INJECTED

ii) Waterfloods on 1½" cores

A total of seven source waterfloods were performed on 1½" cores. The results from Run No. 6 are typical of those from all of these floods and will be discussed here. Results of all other floods are included in Appendix D in the form of tables and/or figures. The oil recovery at water breakthrough and ultimate oil recovery were not duplicated in different cores. This may be attributed to variations in the initial conditions of the cores which are caused by the dry packing technique employed.

Figure 11 shows that the oil recovery from this flood was approximately 40% of the initial oil in place at 1.5 cumulative total pore volume injection.

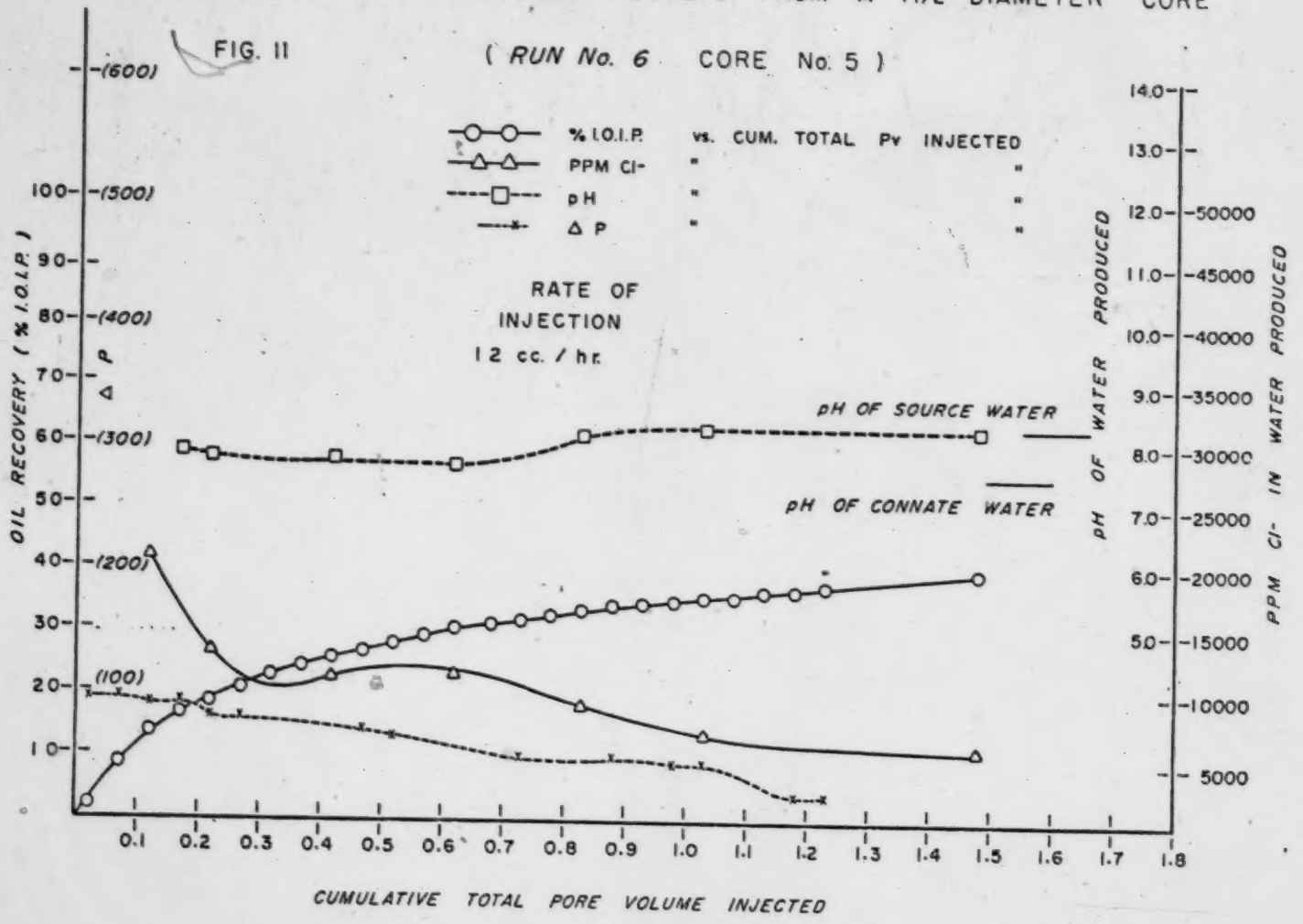
The pH of the effluent at initial water production was 7.85, increasing to 8.26 at the end of the flood. The initial pH value was approximately that of the connate water while the terminal pH value was that of the source water. This result was different from the observation made in the 2" diameter core waterfloods in which the terminal pH value was approximately that of connate water's.

The chloride ion concentration of the effluent at initial water production was a maximum value, approximately

REPRESENTATIVE SOURCE WATERFLOOD RESULTS FROM A 1 1/2" DIAMETER CORE

FIG. 11

(*RUN No. 6* CORE No. 5)



20,000 ppm. This was the lowest of all the corresponding values from floods on 1½" diameter cores. All other floods showed a maximum value of chloride ion concentration of the order of 40,000 ppm at water breakthrough. This low value might have been due to a delay in sampling in this flood. At that time the native water had already been diluted by the source water.

The rate of injection was constant at 12 cc/hr. The pressure drop decreased uniformly as the injection was continued.

Figure 12 illustrates that the producing water-to-oil ratio increased uniformly from the moment of initial water production.

Table 4 on P 58 is a summary of the flooding conditions and oil recovery results of all the waterfloods on 1½" and 2" diameter cores. The amount of oil recoveries was quite similar for all the floods with the exception of Run #10 on core #7. This particular core had a much higher absolute permeability than the other cores. The relative permeability to oil and water in this core may be different than that in the other cores. As a result of this the oil recovery was higher.

FIG. 12 TYPICAL WATER-TO-OIL RATIO HISTORY OF A WATERFLOOD ON A 1 1/2" CORE

(Run No. 6 , CORE No. 5)

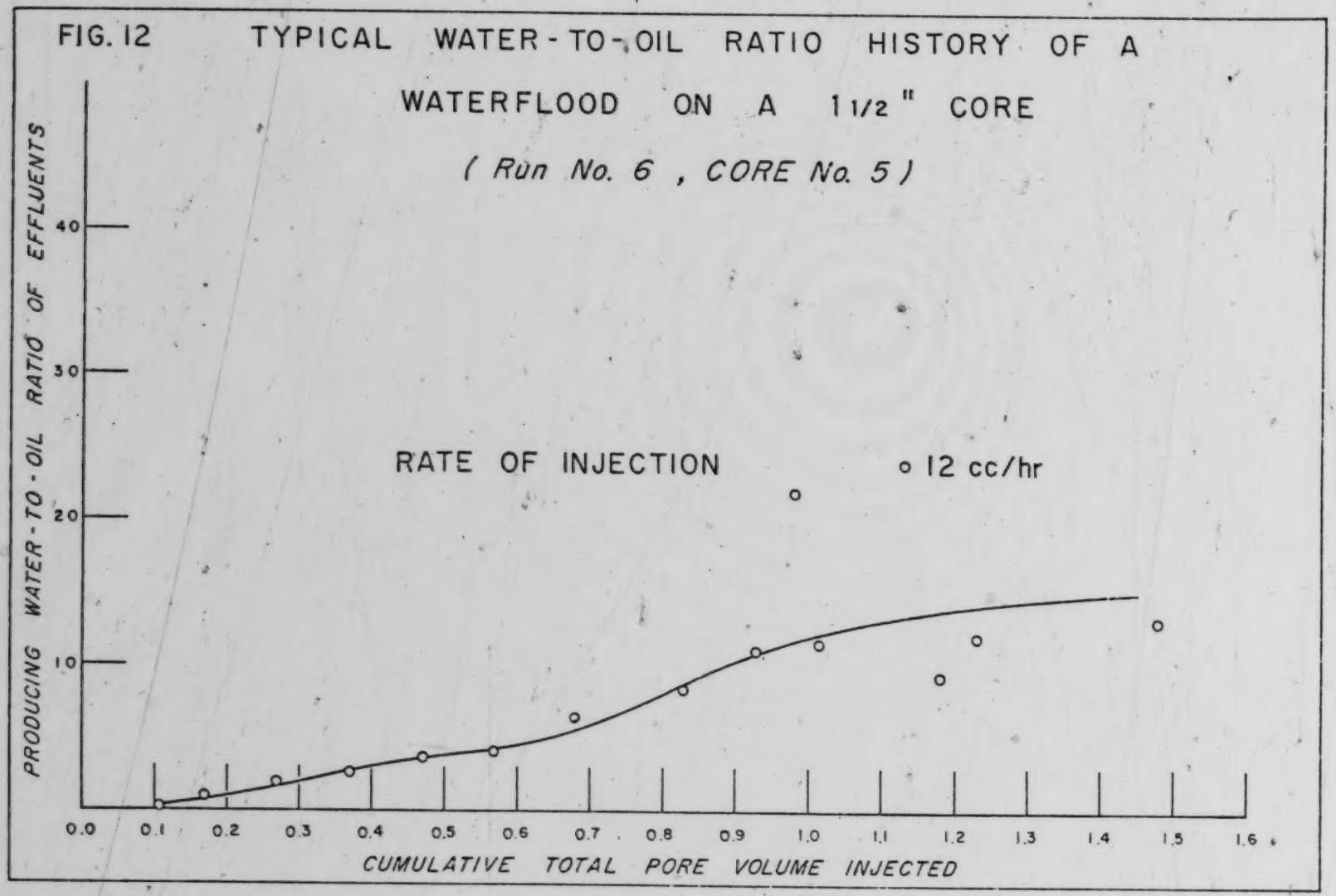


TABLE 4 Waterflood Results Summary

Run #	Core #	Core Diameter (inch)	Rate of Injection (cc/hr)	Initial Water Saturation (%)	Crude Oil Used	% IOIP Recovered Before Water Production	Ultimate % IOIP Recovered @ 1.5 pv Cum inj. (approx)	Cum Total Pore Volume Injected
1	1	2	20.0	0.21	1	8.87	45.41	1.57
2	2	2	20.0	0.21	1	3.64	37.89	1.7
3	3	2	20.0	0.22	1	4.49	37.15	1.46
5	4	1.5	12.0	0.22	1	5.41	42.93	1.69
6	5	1.5	12.0	0.20	1	8.37	39.42	1.48
7	5	1.5	12.0	0.13	1	14.94	44.15	1.83
8	6	1.5	12.0	0.20	1	9.55	45.20	1.79
9	5	1.5	50.0	0.14	1	12.18	44.77	2.10
10	7	1.5	12.0	0.20	1	35.42	53.95	1.84
11	7	1.5	12.0	0.13	2	9.59	37.62	1.93

* Crude Sample 1 is dry crude diluted with n-heptane

2 is dry crude undiluted

After the waterfloods were completed, the cores were resaturated with crude oil and sodium hydroxide floods were performed.

(b) Sodium Hydroxide Floods

Sodium hydroxide floods were performed both on 1½" and 2" cores. The results of these caustic floods were compared to corresponding waterfloods on the same cores. In the case of the 2" cores, the caustic floods obtained a much higher oil recovery than the waterfloods. For the 1½" cores, the caustic floods recovered only slightly more or less oil than the waterfloods. Oil-in-water emulsions were obtained in every caustic flood on 2" cores but only in one flood on 1½" diameter cores.

i) Caustic floods on 2" diameter cores

There were four caustic floods performed on the 2" diameter cores (Run No. 12, 13, 14, 15). The slug size of the caustic used was the same in each flood but the concentration was different. Run No. 12 will be discussed in detail to illustrate the typical flood results from a 2" diameter core. With the exception of the amount of oil recovered, all caustic floods on 2" cores had fairly similar flood results. Results for Run No. 13, 14, 15 are included in Appendix E.

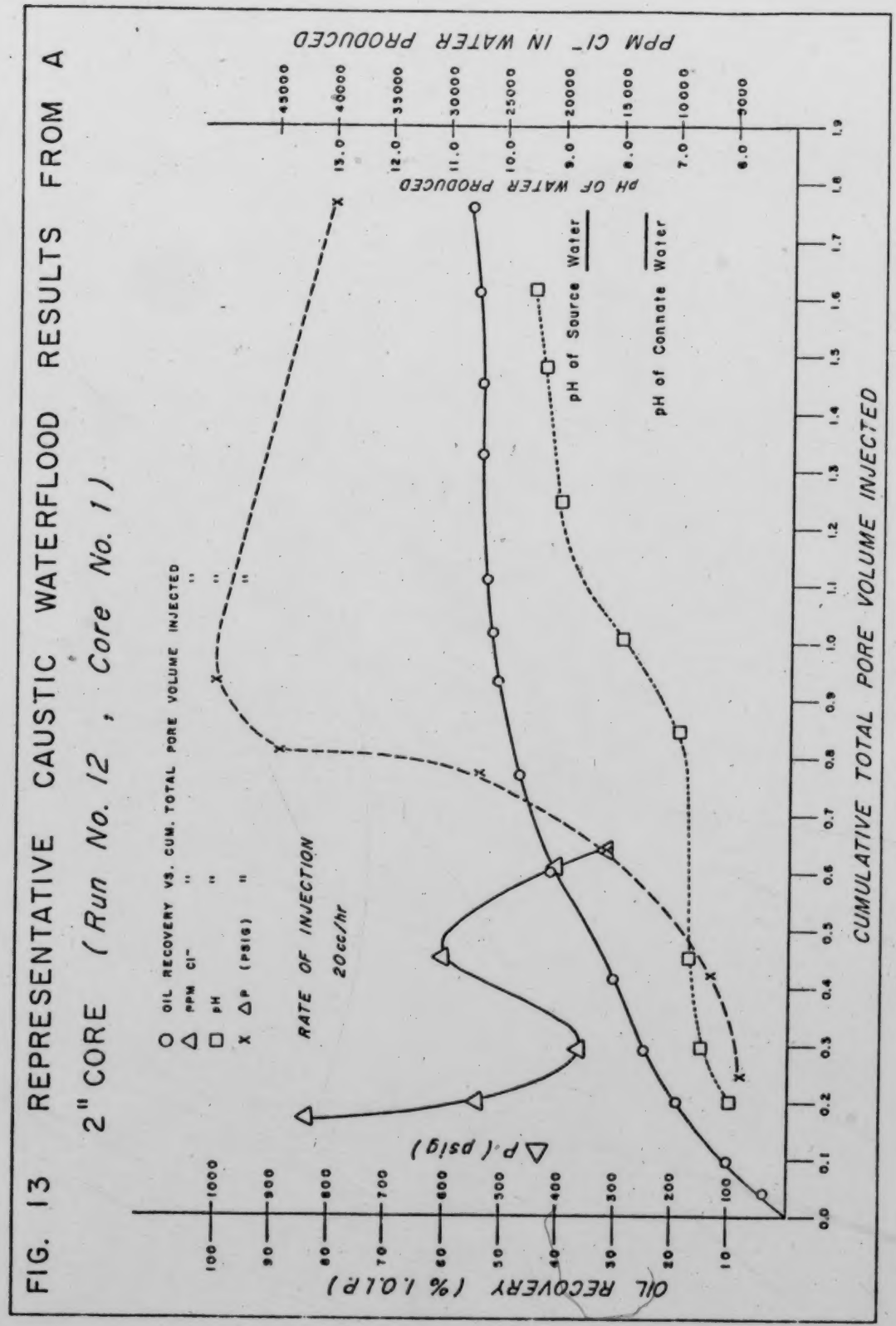

OIL RECOVERY (% I.O.I.P)
ΔP (psig)
CUMULATIVE TOTAL PORE VOLUME INJECTED
PPM Cl⁻ IN WATER PRODUCED
pH OF WATER PRODUCED
pH of Source Water
pH of Connate Water
RATE OF INJECTION
20cc/hr
O OIL RECOVERY VS. CUM. TOTAL PORE VOLUME INJECTED
Δ PPM Cl⁻ "
□ pH "
X ΔP (PSIG) "

FIG. 13 REPRESENTATIVE CAUSTIC WATERFLOOD RESULTS FROM A 2" CORE (Run No. 12 , Core No. 1)

Figure 13 shows that the oil recovery from Run No. 12 was 54% of the initial oil in place at 1.5 cumulative pore volume injection. The concentration of the caustic used was 2.0 wt %. This flood recovered the least amount of oil out of all floods. In subsequent floods, the concentration of the caustic was increased. As a result, the amount of oil recovery also increased with the corresponding increase in NaOH concentration up to 6.0 wt %. There was no further increase in recovery for concentrations higher than 6.0 wt %. At this concentration, the amount of oil recovered was 72% of the initial oil in place at 1.5 cumulative total pore volume injection. The recovery obtained by chemically flooding the 2" cores was significantly higher than that obtained by a plain waterflood on the same system.

The pH of the effluent increased sharply once the caustic broke through to the exit end of the core. The maximum value of the effluent pH for Run No. 12 was only 9.5. This was low when compared to the other floods which had pH values up to 13.0. Since only 2.0 wt % NaOH had been used in this flood, most of the caustic had been consumed. The residual caustic concentration in the effluent was low and therefore caused a low pH reading. Higher concentrations of caustic were used in the other floods which had a correspondingly higher residual

caustic concentration and pH in the effluent. All of the other floods exhibited a similar sharp increase in pH as the caustic broke through to the producing end.

Figure 13 shows that the chloride ion concentration of the effluent was at a maximum in the early stages of the caustic flood following which it decreased gradually, just as in the waterfloods. However, the concentration began to increase again at 0.4 cumulative pore volume injection, before finally decreasing steadily. This was observed in all the caustic floods on 2" diameter cores and was different from the waterfloods. The chloride ion concentration did not increase again after the initial decrease in the waterfloods.

For Run No. 12, the pressure drop across the core increased to 1000 psig from 88 psig after the injection of the caustic slug. This was the highest of all the four floods. The amount of increase in pressure drop, however, was not related to the concentration of sodium hydroxide used. This increase in pressure drop was observed in all the caustic floods on 2" cores. Furthermore, the pressure drop in all the sodium hydroxide floods was higher than source waterfloods on the same cores.

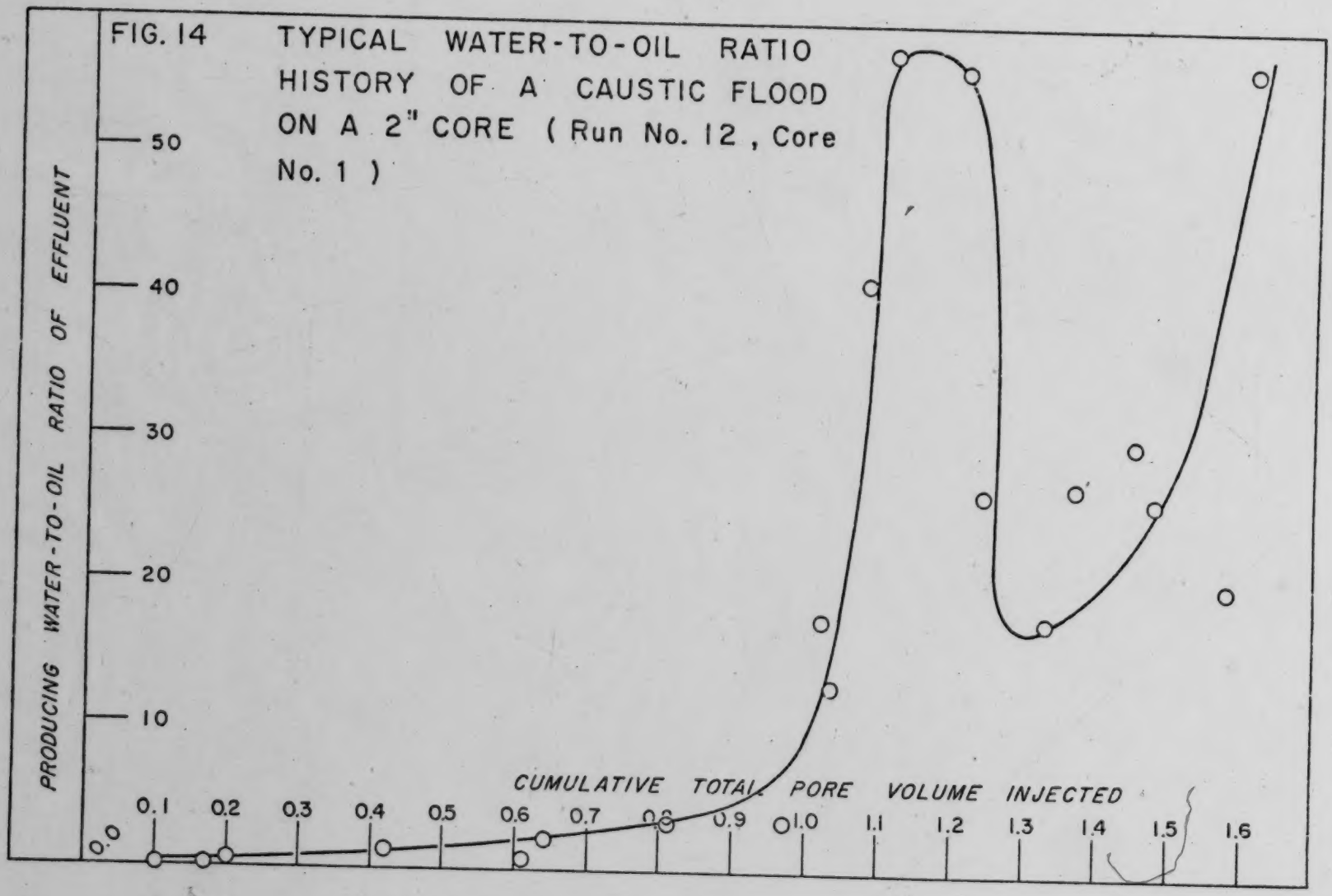
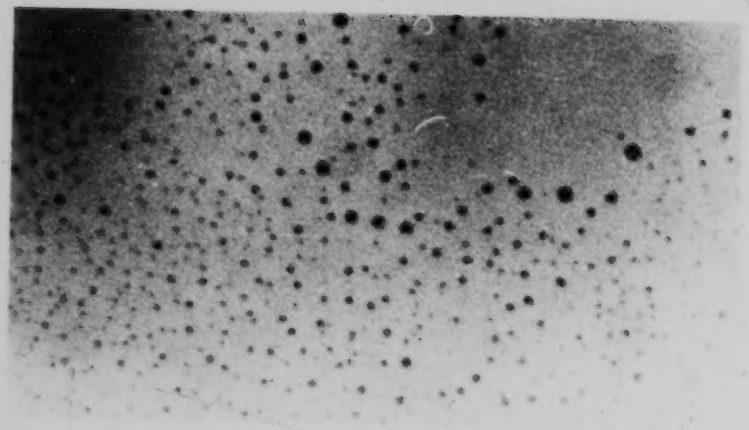


FIG. 14 TYPICAL WATER-TO-OIL RATIO HISTORY OF A CAUSTIC FLOOD ON A 2" CORE (Run No. 12 , Core No. 1)

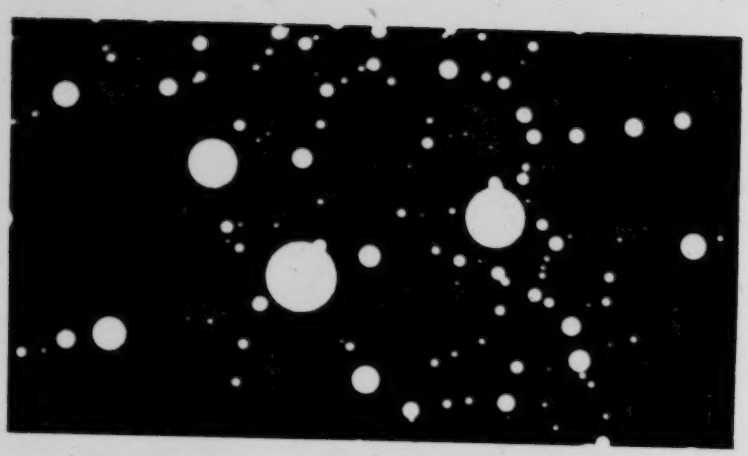
Figure 14 illustrates the water-to-oil ratio (W.O.R.) of the produced fluids for Run No. 12. It is seen that the W.O.R. increased to a maximum at 1.1 cumulative total pore volume injection and then decreased sharply, before increasing again subsequently. This is different from the source waterflood in which the W.O.R. increased steadily from the moment of initial water production till the end of the flood. Such effect was not so pronounced in Run No. 13, 14, 15. However, at the same cumulative pore volume injected the W.O.R.'s of all the sodium hydroxide floods were found to be lower than that observed for pure waterfloods on the same system.

Emulsions were observed in the produced fluids from all the sodium hydroxide floods on 2" diameter cores. The formation and production of these emulsions was responsibile for the different results between the caustic floods and waterfloods, such as described above.

Fig. 15 shows the photographs of these emulsions under the microscope. Oil droplets may be seen suspended in the water phase of the emulsions. As a result the emulsions were classified as an oil-in-water type.

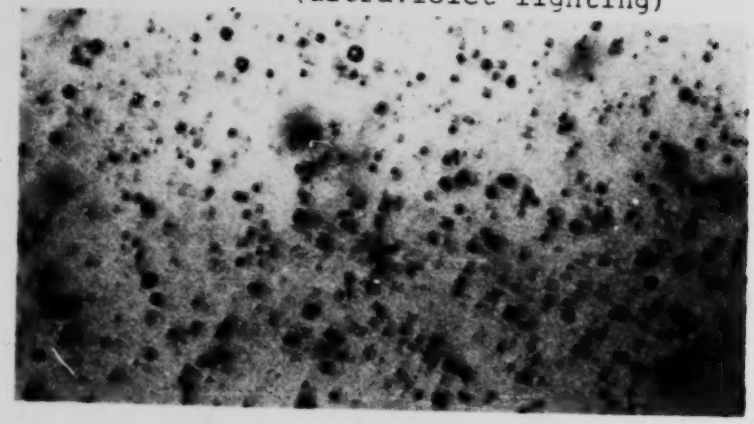


(a) Run no. 12,2% NaOH used



(b) Run no.13, 4% NaOH used
(ultraviolet lighting)

(c) Run no.14, 8% NaOH used



(d) Run no.15, 6% NaOH used

Fig 15 Oil in Water Emulsions produced in Runs 12,13,14,15 (NaOH floods)

ii) Caustic floods on 1½" cores

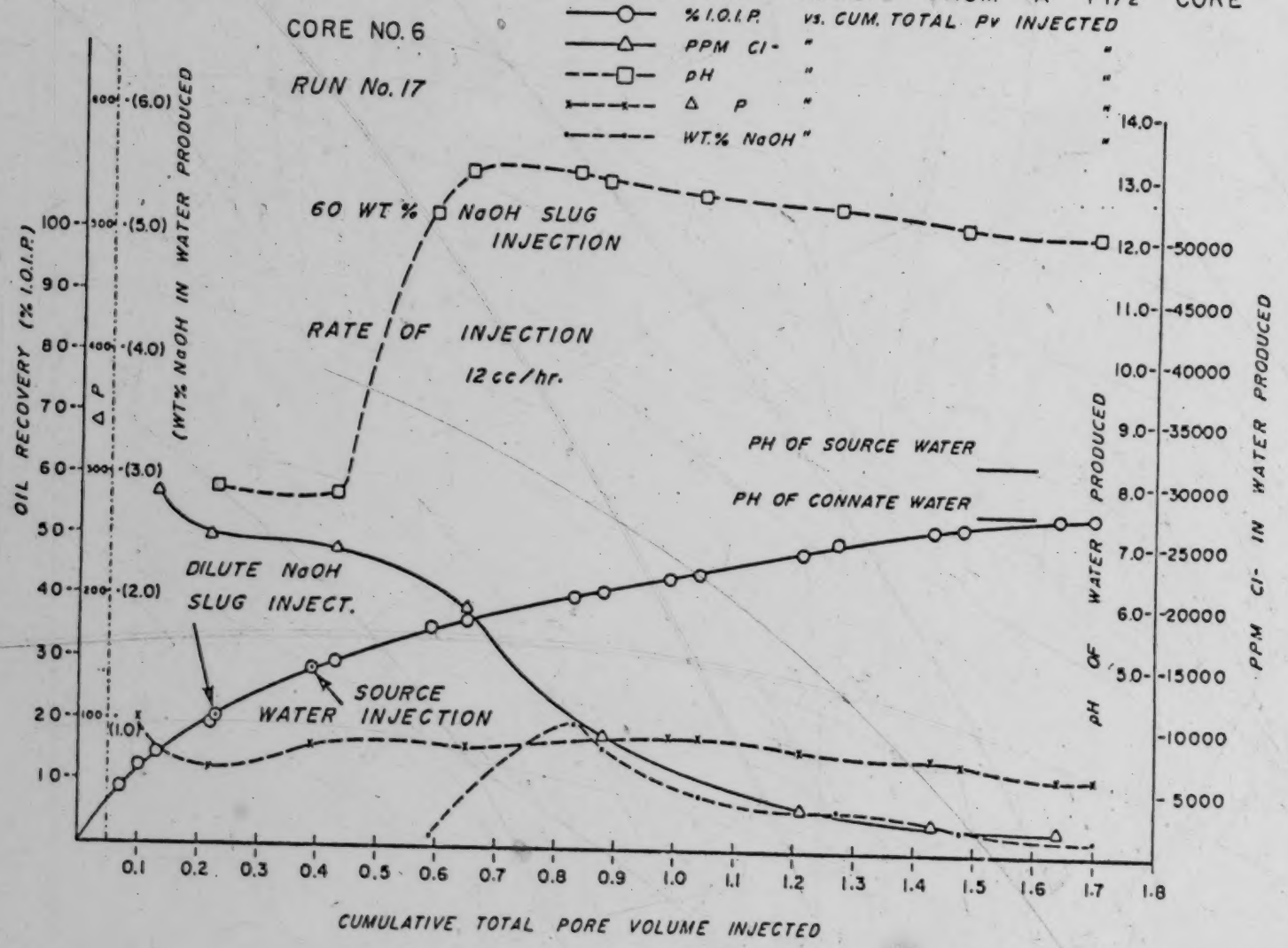
A total of seven sodium hydroxide floods (Run. No. 16-22) were performed on 1½" diameter cores. The sodium hydroxide concentration used was constant at 6.0 wt %. There was only one caustic flood (Run No. 22) which caused oil-in-water emulsions to be produced from the core system.

Figure 16 illustrates the results of the sodium hydroxide flood on core No. 6, Run No. 17. These results are typical of caustic floods during which there was no production of emulsions. These floods included Run No. 17-21 the results of which are included in Appendix E.

The oil recovered in Run No. 17 was approximately 53% of original oil in place at 1.5 cumulative pore volumes injection. The waterflood on the same core however, recovered 45% of original oil in place at the same amount of injection. This caustic flood recovered slightly more oil than a water-flood.

The pH of the effluent increased sharply to 12.48 at the moment of caustic breakthrough. The residual sodium hydroxide concentration was maximum at 0.85 cumulative total pore volume injection.

FIG. 16 REPRESENTATIVE CAUSTIC WATERFLOOD RESULTS FROM A 1 1/2" CORE



The chloride ion concentration of the initial water production was 28,000 ppm. This concentration stayed quite constant between 0.2 to 0.4 cumulative pore volume of injection and then decreased gradually as the flood was continued.

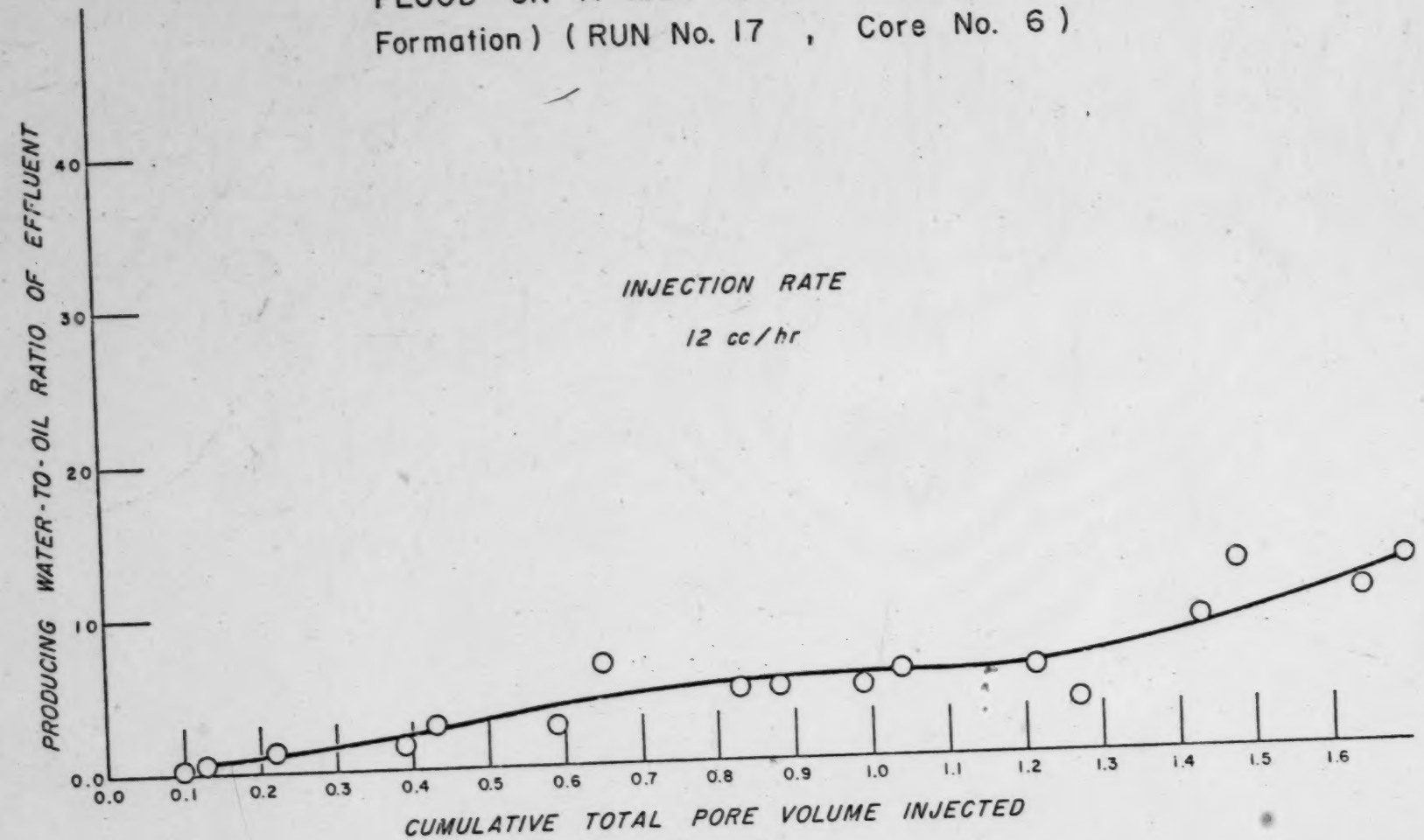
The pressure drop across the core showed some increase between 0.2 to 0.4 cumulative total pore volume of injection, after the sodium hydroxide was injected. The pressure drop them remained quite constant during the rest of the flood. The amount of increase in pressure, however, was very small compared to that obtained in the 2" cores.

The residual sodium hydroxide concentration in the effluent was measured to indicate whether the caustic had been consumed for emulsions formation. The highest concentration of the caustic detected was 1.0 wt %.

Figure 17 illustrates the producing water-to-oil ratio of the effluent during the flood. It is clear that the W.O.R. increased steadily as injection continued.

It was apparent from the caustic flood results of 2" diameter cores that emulsification was necessary to achieve a substantial increase in oil recovery. Results from Run No. 16 and 17 on the 1½" cores confirmed this. There were no emulsions produced in these two caustic floods. As a

FIG. 17 WATER-TO-OIL RATIO HISTORY OF A CAUSTIC FLOOD ON A 1 1/2" CORE (Without Emulsion Formation) (RUN No. 17 , Core No. 6)



result, the oil recoveries obtained were just slightly more or less than that obtained in waterfloods on the same cores.

Consequently, a number of changes in flooding conditions were made in an attempt to create emulsions. Each modification to the flood is described.

In Run #18, caustic was injected at the start of the flood, without the usual initial injection of source water. A continuous slug of caustic at 6.0 wt % concentration was used. The flood was terminated when 1.82 cumulative pore volumes of caustic had been injected.

In Run #19, the rate of injection was changed to 50 cc/hr. in order to achieve a better rate of mixing between the fluids. The rate of injection in previous floods on 1½" cores was only 12 cc/hr.

A core made up of a different sand was used in Run #20. This sand was obtained from a heavy oil reservoir in Saskatchewan and was used in Run #20, 21, 22.

The crude oil used in the above floods was dry Wainwright crude oil diluted with n-heptane. In Run No. 21, this crude oil was replaced with the undiluted Wainwright crude.

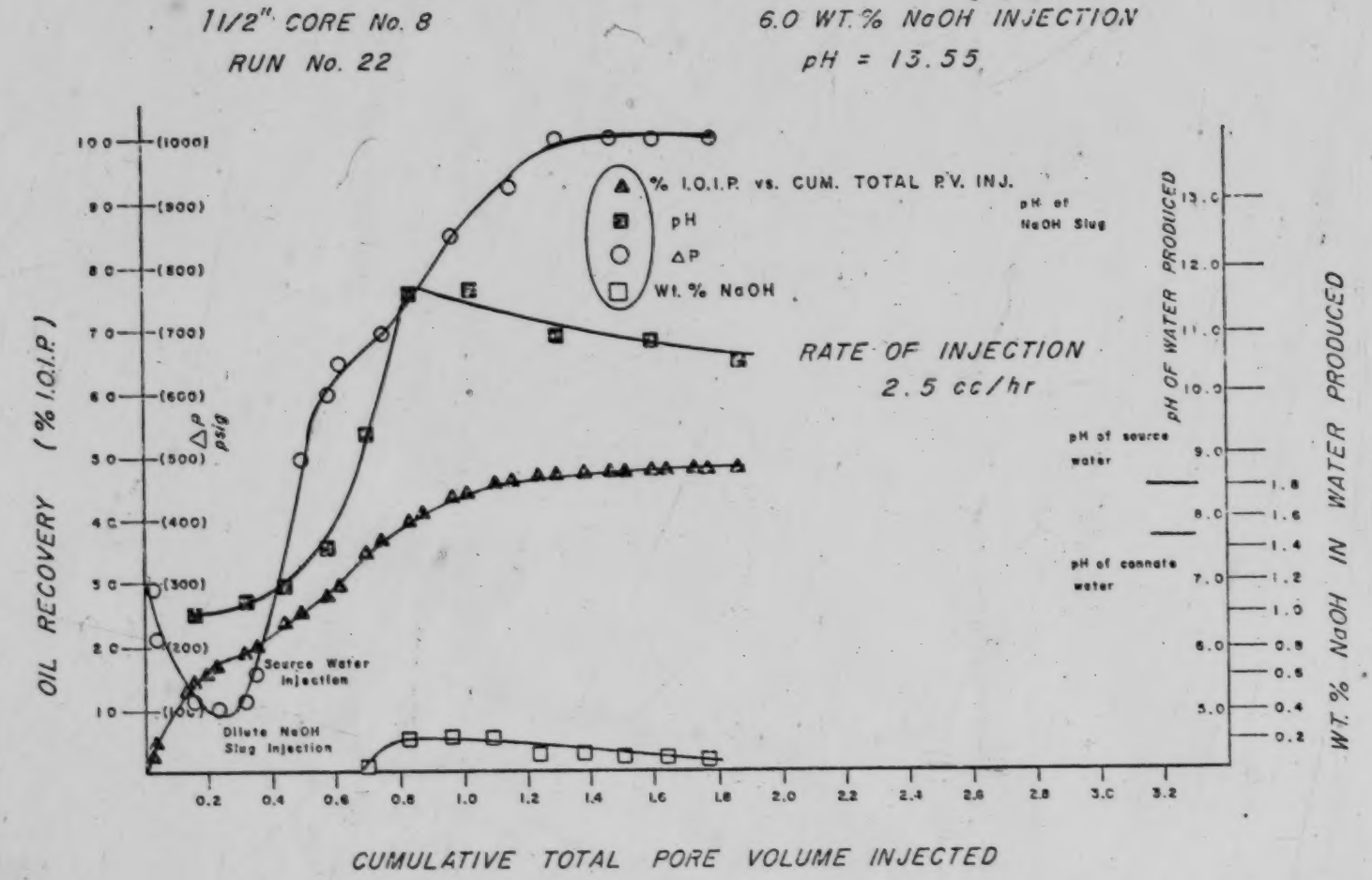
All of these changes in flooding conditions however, did not cause the formation of emulsions in the caustic floods on 1½" cores. When the results of these floods were compared to corresponding waterfloods on the same cores, it was found there was no substantial increase in oil recoveries as had been observed with the 2" cores.

During the final caustic flood on a 1½" core in Run No. 22 the injection rate was lowered to 2.5 cc/hr. This was intended to give the caustic a longer residence time in the core so that it might react with the crude. Emulsions similar to that observed in the caustic floods on 2" cores were obtained.

Figure 18 shows the results obtained from Run No. 22. The oil recovery was approximately 48% of the initial oil in place at 1.5 cumulative total pore volume injection. There was no waterflood performed on this core so the oil recovery could not be compared to a standard.

The pressure drop across the core was quite similar to that of Run No. 12 on the 2" core. After injection of the caustic, the pressure drop began to increase, until it reached 1000 psig at 1.2 cumulative pore volume injection. This increase in pressure drop was observed in all the floods which produced emulsions.

FIG. 18 EFFECT OF DECREASED INJECTION RATE ON CAUSTIC FLOOD OIL RECOVERY RESULTS



The concentration of the residual sodium hydroxide was very low, at 0.24 wt %. This indicates most of the caustic was either consumed or adsorbed in the core system during the flood.

Figure 19 illustrates the producing water-to-oil ratio history of Run No. 22. At any stage of this flood, the steadily increasing water-to-oil ratios did not show such a sudden decrease as in the caustic flood on the No. 1, 2" core. (Fig. 14, Run No. 12) There were only slight, periodic decreases in Run no. 22.

Table 5 summarizes the results of all the sodium hydroxide floods on 1½" and 2" cores. Emulsions were obtained in all floods on the 2" cores. The oil recovery from these cores were also much higher. In the 1½" cores, only Run #22 on core #10 produced any emulsions. The breakthrough time for the caustic was also the longest for Run #22 out of all caustic floods since the injection rate was only 2.5 cc/hr.

FIG.19 PRODUCING WATER-TO-OIL RATIO HISTORY OF CAUSTIC FLOOD ON 1·5" CORE No.10 (RUN No 22)

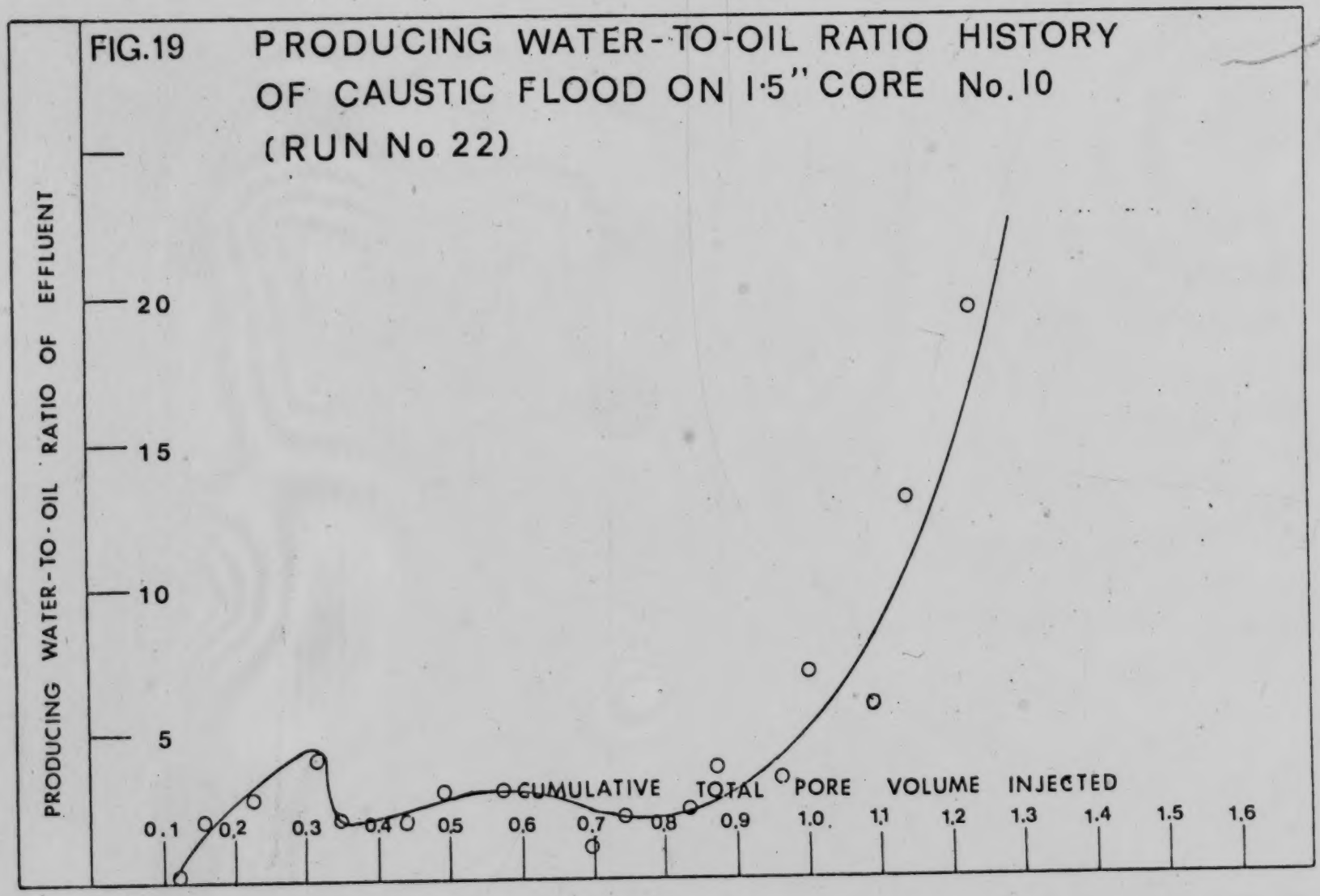


TABLE 5

Sodium Hydroxide Flood Results

Run #	Core #	Core Diameter (inch)	Rate of Injection (cc/hr)	Initial Water Saturation (% pv)	Wt % NaOH Used	Ultimate % IOIP Recovered @ 1.5 pv Injection	Size of Pre-NaOH Water Slug (pv)	NaOH Slug Size (pv)	Emulsion Formation	NaOH Break Through Time (after injection)
12	1	2	20	13.79	2	54.5	0.24	0.17	YES	35 hrs
13	2	2	20	17.56	4	64.53	0.24	0.17	YES	30 hrs
14	3	2	20	18.7	8	70.50	0.24	0.17	YES	27 hrs
15	9	2	20	23.59	6	72.19	0.24	0.17	YES	20 hrs
16	4	1.5	12	19.71	6	35.0	0.24	0.17	NO	11 hrs
17	6	1.5	12	20.3	6	53.0	0.24	0.17	NO	14 hrs
18	6	1.5	20	21.23	6	50.0	0	1.82	NO	11 hrs
19	5	1.5	50	15.49	6	35.0	0.24	0.17	NO	2 hrs
20	8	1.5	12	16.42	6	51	0.24	0.17	NO	18 hrs
21	7	1.5	12	23.57	6	46.0	0.24	0.17	NO	5 hrs
22	10	1.5	2.5	19.45	6	47.8	0.24	0.15	YES	66 hrs

DISCUSSION

The mechanisms by which caustic waterflooding helps to increase oil recovery have been discussed previously. From the experimental results of this study, it is apparent that two of those mechanisms may have been involved in the successful caustic floods. These floods showed an increase in oil recovery, when compared to waterfloods, only when there was the production of oil-in-water emulsions. The postulated mechanisms responsible for this increase were:

(1) Emulsification and Entrainment (9)

(2) Emuslification and Entrapment (21)

Emulsifying agents are formed when the carboxylic acids of the crude oil react with caustic solutions. These emulsifying agents lower the interfacial tension between the caustic water and the crude oil and facilitate the formation of emulsions. The interfacial tension data obtained in this study (see Figure 2) indicated that a minimum of the interfacial tension between Wainwright crude oil and caustic water did occur at approximately a 0.5 weight percent concentration of sodium hydroxide. This result suggested that emulsions would likely be formed between Wainwright crude oil and sodium hydroxide if sufficient sodium hydroxide were used to account for all expected consumption, adsorption and reaction in the system. Based upon the results of this investigation a concentration of 6% by weight of sodium hydroxide in water was selected for the study.

Waterfloods on 2" Cores

The average oil recovery from the waterfloods on the 2" cores was approximately 40% of the initial oil in place at 1.5 cumulative pore volume of water injection. Referring to Figure 9, when water production first occurred the chloride ion concentration was at a maximum value, slowly decreasing as the flood continued. This indicated that the native initial connate water, which had a very high chloride ion concentration, was displaced from the pores by the injected source water.

The observed pH performance of the produced fluids in a plain waterflood, previously described, was analyzed in an attempt to describe the waterflood mechanism. The behavior of pH, and the chloride ion concentration of the produced fluids as described above supports the conclusion that source water displaced connate water. The water-to-oil ratio increased steadily as expected for a normal waterflood.

Caustic Floods on 2" Cores

The oil recovery obtained from the caustic floods on the 2" cores was much higher than that of the waterfloods. Depending on the concentration of the caustic slug used, 54% - 72% of the original oil

in place was recovered at 1.5 cumulative total pore volume injected. The table below shows that there was a direct correlation between oil recovery and concentration of caustic used.

Run #	Core #	Wt % NaoH Used	Ultimate % IOIP Recovered @ 1.5 PV Injection
12	1	2.0	54.50
13	2	4.0	64.53
14	3	8.0	70.50
15	9	6.0	72.19

As the concentration increased so did the oil recovery, until at 6% when no more increase in oil production was obtained with further increases in NaOH concentration.

Referring to Figure 13 when water was first produced, the chloride ion concentration of the effluent was at a maximum value. As the flood continued the chloride ion concentration decreased. However, at approximately 0.2 - 0.4 pore volume injection the chloride ion concentration started to increase again. This was different from that observed in the waterfloods.

The pH of the effluent started to rise as the caustic began to be produced at the exit end. The maximum pH of the effluent from the 2% NaOH flood was only 9.5. As the concentration of the caustic slug increased so did the maximum value of pH of the effluent.

As the flood continued and oil-in-water emulsions began to be produced, the pressure drop across the cores began to increase. This increase was sustained over the rest of the flooding period. The production of emulsions and increase in pressure drop were observed in all caustic floods on 2" cores.

At all stages of the caustic floods, the water-to-oil ratios of the effluent were lower than the waterflood on the same cores. In Run #12, Fig 14, it might be seen that the WOR was starting to increase at 1.0 cumulative pore volume injection. However, this did not persist and the WOR started to decline again for a good portion of the flood before increasing to higher values.

The sodium hydroxide had reacted with the crude oil to form emulsifiers which facilitated the formation of oil-in-water emulsions. The emulsified oil was entrained in the caustic solution and source water and subsequently produced. Some of the emulsion droplets might have been lodged in the more permeable sections of the core where the pore throats were not large enough for them to pass through. As a result the established channels of flow were blocked and there was a corresponding increase of pressure drop across the core. This is similar to what McAuliffe (30) has observed when he studied the simultaneous flow of emulsions through cores of different permeabilities. Injected water was diverted to other parts of the core. The smaller pores which normally would not have been swept by the injected water were now invaded. The oil present in these pores was

now produced. As a result there was a very large increase in oil recovery when compared to that obtained by a plain source waterflood.

The sudden increase in chloride ion concentration of the produced fluids also supported the above postulation. The native water present as irreducible water saturation in the pores had a high chloride ion concentration. The injected source water displaced this native water our of the pores and it was this water which initially displaced the oil out of the core. In a plain source waterflood the source water only passed through certain parts of the core where the permeability to flow was higher. Therefore the chloride ion concentration would decrease monotonically because all the native water would have gradually been swept out. When the normal passage ways were blocked by the emulsions in a caustic flood, new channels of flow had to be established. The source water now invaded the smaller, unswept pores. The native water in these pores was produced with a corresponding increase in chloride ion concentration of the effluent.

It was also noticed that the producing water-to-oil ratios of the effluents suddenly decreased during a successful caustic flood. In the region blocked by emulsions, the injected water mobility was decreased. As more water was diverted to other channels of flow to sweep out the otherwise immobile oil, the producing water-to-oil ratios would drop. A large increase in pore volume sweep efficiency was obtained.

Waterfloods on the 1½" Cores

These waterfloods recovered approximately 45% of the initial oil-in-place at 1.5 cumulative total pore volume of water injection. (See Figure 11). The chloride ion concentration of the produced fluids decreased uniformly from a maximum at initial water production. The pH value of the water produced initially was between that of the source and native water, rising gradually to that of the source water. This initial pH value was different from that observed in the waterfloods on a 2" core. The pH of the initial water production in a 2" core was always lower than either that of the source or native water. No explanation could be offered for this observation. The pressure drop across the cores decreased uniformly during the floods. Referring to Figure 12, the WOR of the produced fluids increased steadily after initial water production.

Caustic Floods on 1½" Cores

No emulsions were formed and produced during the first two caustic floods on 1½" cores. The oil recovery was slightly more or less than that obtained for the corresponding waterflood. Referring to Figure 16, the chloride ion concentration levelled off between 0.2 - 0.4 cumulative pore volume of injection. The pressure drop across the cores increased slightly during the same stages of the flood. This suggests that the emulsion forming mechanism was trying to operate, but failed for some unknown reasons. When the caustic broke through to the producing end, the pH of the effluent started to

rise. As only a fixed concentration of caustic at 6.0 wt % was used in all caustic floods on 1½" cores, the effluent pH of all the cores increased to a value of approximately 13.0 gradually. The producing WOR of the effluent increased monotonically during the flood, after initial water production was obtained (See Figure 17).

Attempts were made to produce emulsion in the balance of the caustic floods on 1½" cores. These included using continuous caustic injection, increasing the rate of injection of both caustic slug and source water, a different sand, and undiluted crude oil. All of these methods failed to produce any emulsions.

It was thought that an excess quantity of caustic might facilitate emulsions formation. Therefore sodium hydroxide at 6.0 wt % was injected continuously into a core pack, until 1.82 cumulative pore volumes had been injected. Emulsions were not produced. Even though there was a slight increase in pressure drop, it was sustained only for a short period after which the pressure drop decreased again. The excess of caustic might have reacted with the native water, causing the formation of precipitates. These precipitates blocked off some pore throats and caused a slight increase in pressure temporarily. The precipitates were later produced along with the fluids and the pressure drop decreased.

The rate of injection was increased to 50 cc/hr for another flood, almost four times that of the previous floods. Again emulsions were not obtained. It was found that the caustic broke through to the

exit end in a very short period of time, with large amounts of residual sodium hydroxide still in the effluent. The increase in rate only caused the caustic to channel through the core, instead of effecting the better rate of mixing with the oil as planned.

Core packs made up of a different type of sand were used next. However, no emulsions were formed either. Results of these caustic floods were similar to the corresponding waterfloods again.

The crude oil used in the floods so far was diluted with n-heptane which might cause the precipitation of the asphaltene fraction of the crude. As the asphaltene fraction might help to stabilize the emulsions, its removal might hinder the formation of emulsions. Undiluted Wainwright crude oil was used for the next core. There was still no emulsion formation in this caustic flood.

Referring to Table 5 (P.75), it was observed that the caustic seemed to have reached the exit end of the 1½" cores in a much shorter time than it did in the 2" cores. This observation did not take into account the fact that at the moment of caustic breakthrough in different floods, the concentration of the caustic detected was not identical. Ideally, the caustic concentration should be small and identical to define breakthrough in every flood. However, due to equipment limitations this was not possible. As a result, the caustic breakthrough time for the different floods could only be used qualitatively. Nevertheless another flood (Run 22) was designed with

a very low rate of injection, 2.5 cc/hr. It took the caustic 66 hrs to be produced at the exit end. Emulsions of the oil-in-water type were obtained. The oil recovery was only about 48% of the initial oil in place. This was approximately what the other caustic floods on 1½" cores had produced. However, the particular core used in this slow injection test had a permeability of only 62 md, as compared to 200 - 1530 md for the other cores. The amount of oil recovery could not be compared on an equitable basis. There were no waterflood results on this core to serve as a reference point either. Nevertheless, emulsions were obtained and it showed that sodium hydroxide did need a long enough residence time to react with the crude oil.

Referring to Figure 18, the pressure drop across this core showed a definite increase when emulsions were produced. The producing WOR was very low compared to the other floods without emulsion formation. However, as shown in Figure 19, the WOR did not show any sudden decrease at any stage of the flood similar to that of the 2" cores in which emulsions were produced.

The pH of the fluids produced initially in Run No. 22 was lower than the pH of the source or native water. This result is different from that of caustic floods on other 1½" cores which did not produce any emulsions. The pH value of the initially produced fluids in those floods was always between that of the source and native water. In caustic floods on 2" cores, all of which produced

emulsions, the same observation in pH values as in Run No. 22 was made. However, no explanation could be offered in regard to this observation.

The same observation can be made with respect to the pH values observed in the waterfloods in the 1½" and 2" cores. This suggests that the flooding mechanisms, for some unknown reason are substantially different in the two systems. That is, some additional variables are confounding the results.

The experimental results show that sodium hydroxide appeared to need a minimum time of reaction with the crude oil to produce emulsions. Without the emulsification of the oil in place there was no increase in oil recovery nor decrease in producing WOR. The emulsions were entrained and entrapped in the core as shown by the chloride ion concentration and pressure drop increase. The successful caustic floods on the 2" cores showed that a large increase in oil recovery could be obtained when compared with source waterflood.

The emulsification of the oil in place, together with the entrainment and entrapment process of the emulsions should make the caustic waterflooding process most beneficial in the recovery of viscous crude oils. Flood water tends to channel easily in viscous oil reservoirs and the sweep efficiency is notoriously poor. This problem is usually compounded by the reservoir rock heterogeneity. The emulsification of the viscous crude oil and the blocking of the more permeable channels should produce a high flooding efficiency.

CONCLUSIONS

Laboratory caustic floods were conducted on aged cores packed with reservoir sand, and saturated with native brine and viscous crude. The results were compared to waterfloods on the same cores.

The main conclusions drawn from the results of this study are:

1) Emulsification of the oil in place appeared to be the key mechanism for increased oil recovery.

2) Sodium hydroxide needed a minimum residence time in the core pack to react with the crude oil for the formation of oil in-water emulsions.

3) Based on the results reported it may be concluded that both entrainment and entrapment of the emulsions occurred in the core packs.

4) High injection rate of sodium hydroxide well in excess of field rates did not create sufficient mixing or shear action to facilitate emulsion formation in the core packs used.

5) Excessive quantities of sodium hydroxide did not cause the formation of emulsions.

6) Both diluted and undiluted Wainwright crude oil exhibited a minimum interfacial tension at a 0.5 wt % concentration of sodium hydroxide. As such, this crude is susceptible to caustic waterfloods for increased oil recovery. The lowering of interfacial tension showed that the crude contains enough reactive components, ie. carboxylic acids, for the formation of emulsifiers.

7) There was an increase in oil recovery with an increase in caustic concentration up to 6.0 wt %. Above 6.0 wt % no increase in oil recovery was obtained when the concentration of the caustic slug was increased. This observation was only valid for the core system used in this study.

RECOMMENDATIONS

1) Emulsification of the oil-in-place has been shown to be the major mechanism for oil recovery increase. Wettability change of the core system however, was not clearly identified. It would be desirable to find out the wettability of the core pack after the aging period and after the sodium hydroxide floods.

2) There was a definite difference in the emulsions formed from dry crude and dry crude diluted with heptane. It would be worthwhile to find out the capability of particular crudes to form emulsions with sodium hydroxide.

3) To determine the applicability of emulsifying the oil by sodium hydroxide in the field, a critical sodium hydroxide residence time for emulsion formation should be determined and this should be verified for field conditions in a pilot test.

4) More work on the consumption of sodium hydroxide by produced water, source water and reservoir rock should be performed. Only by knowing the exact consumption would a field process of sodium hydroxide flooding be justified.

5) A different core packing technique should be investigated. The dry packing technique employed in this study did not give exact initial conditions in each core.

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APPENDIX A

Properties of Sand and Fluid

TABLE A-1

Sand Screen Analysis

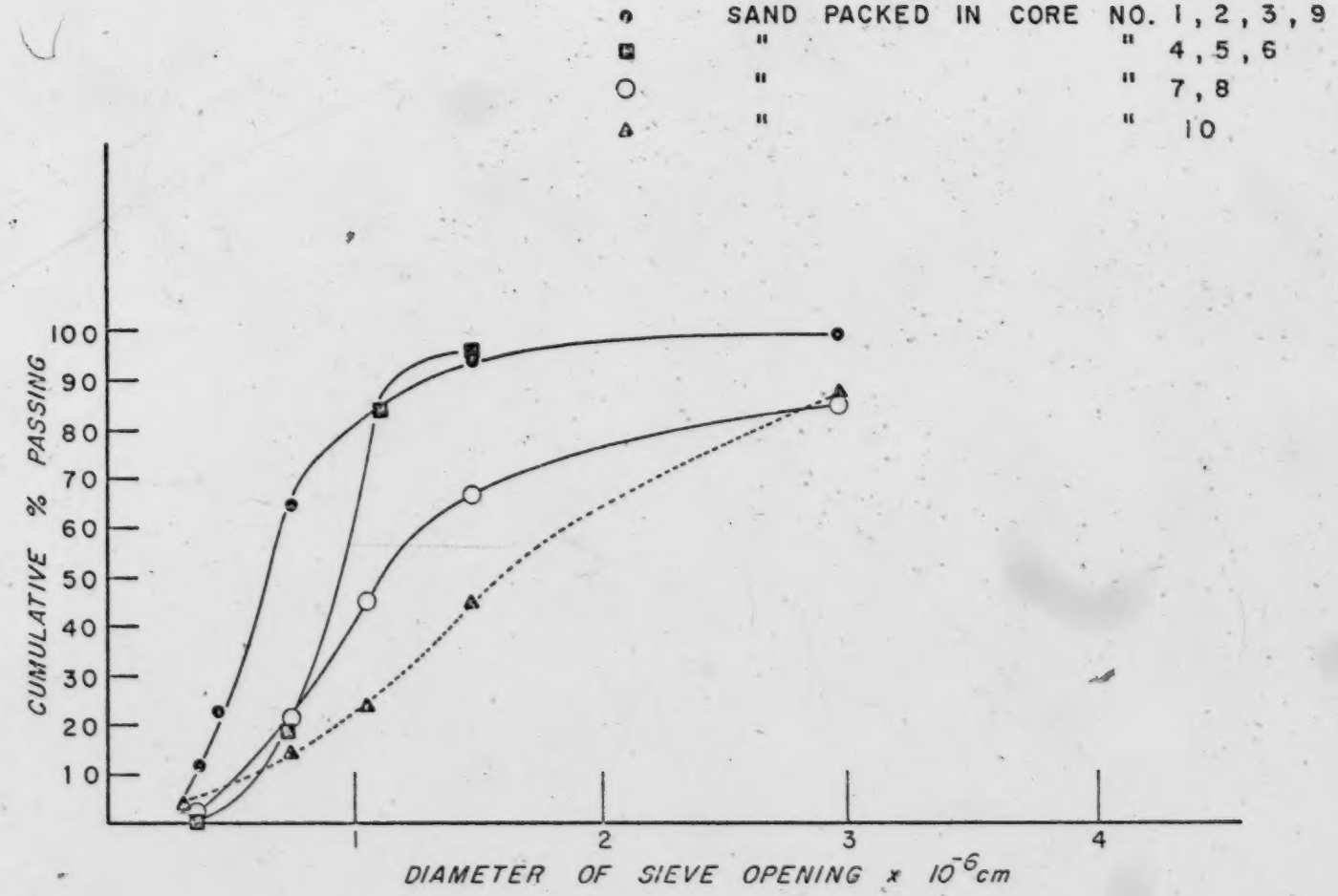
GRAIN SIZE		CUMULATIVE MASS % OF SAND WHICH FLOWED THROUGH SCREEN			
Mesh Size	cm	Sundance Kinsella Sand For 2" Cores	Sundance Kinsella Sand For 1½" Cores	Saskatchewan Sand (1)*	Saskatchewan Sand (2)**
48	0.0295	99.97	N/A	84.3	87.1
100	0.0147	94.55	96.6	66.9	44.7
150	0.0105	N/A	94.48	45.0	23.9
200	0.0074	64.73	19.49	20.6	14.6
325	0.0044	22.6	N/A	N/A	N/A
400	0.0037	11.23	0.64	0.054	0.3

N/A - The particular size of mesh was not used

(1)* Sand Used For Cores #7 and #8

(2)** Sand Used For Core #10

FIG. A-1 SIZE ANALYSIS OF SAND PARTICLES



Calculation of the Mean Mass Diameter, $\Sigma D_p\emptyset$

A. Sundance Kinsella Sand used for 2" core

Mesh	D_p, Opening Diameter, cm	Mass Fraction, $\emptyset$	$D_p \times \emptyset$ cm
48	0.0297	0.00039	1.1583×10^{-5}
100	0.0149	0.061	9.098×10^{-4}
200	0.0074	0.3359	2.4856×10^{-3}
325	0.0044	0.4745	2.0878×10^{-3}
400	0.0037	0.1281	4.7397×10^{-4}

Mean Mass Diameter $= \Sigma D_p\emptyset = 0.00596$ cm

B. Sundance Kinsella Sand used for 1½" cores

Mesh	D_p, cm	Mass Fraction, $\emptyset$	$D_p \times \emptyset$ cm
100	0.0147	0.034	4.998×10^{-4}
150	0.0105	0.021	2.998×10^{-4}
200	0.0074	0.754	5.579×10^{-3}
400	0.0037	0.189	6.99×10^{-4}

Mean Mass Diameter = 0.00699 cm

C. Saskatchewan Sand

(a) For Cores #7 and 8

Mesh	D_p, cm	Mass Fraction, Ø	D_p x Ø cm
48	0.0297	0.166	4.9×10^{-3}
100	0.0149	0.184	2.7×10^{-3}
150	0.0105	0.231	2.4×10^{-3}
200	0.0074	0.257	1.9×10^{-3}
400	0.0037	0.160	0.59×10^{-3}

The Mean Mass Diameter = 0.01249 cm

(b) For Core #10

Mesh	D_p, cm	Mass Fraction, Ø	D_p x Ø cm
48	0.0297	0.129	0.0038
100	0.0149	0.424	0.0063
150	0.0105	0.208	0.0021
200	0.0074	0.093	0.00068
400	0.0037	0.143	0.00052

The Mean Mass Diameter = 0.0134 cm

TABLE A-2

Chemical Composition of Sundance
Kinsella Sand (Cores #1,2,3,9)

Composition of sand before sodium hydroxide floods:

Chemical Elements	% by Weight
SiO_2	85.9
R_2O_3	7.7
ignition loss	2.7
Ca,Mg	3.7

The radical, R, stands for either Fe_2 or Al_2. About 3% of the R_2O_3 was Fe_2O_3 and about 97% was Al_2O_3.

Composition of sand after sodium hydroxide floods:

Chemical Elements	% by Weight
SiO_2	84.7
R_2O_3	9.5
ignition loss	2.5
Ca,Mg	3.3

About 5% of the R_2O_3 was Fe_2O_3 and the remainder 95% was Al_2O_3.

TABLE A-3

SUMMARY OF WATER ANALYSIS*

Water Sample	CONCENTRATION OF IONS, PPM							
	Cl^-	Ca^{++}	Mg^{++}	Na^+	K^+	CO_3^{--}	HCO_3^-	pH
Source Water	236	3.5	1.0	430	8.6	36.0	701.5	8.78
Native Water								
# 1	46,000	2,851	1,156	22,500	1,400	-	86.5	7.58
# 2	47,000	2,795	1,451	23,250	1,400	-	60.4	7.54
# 3	47,000	2,723	1,423	23,250	1,400	-	81.1	7.47
# 4	46,000	2,891	1,312	22,750	1,400	-	78.1	7.66

* After Ref. 29

TABLE A-4

Properties of Crude

Type	Density		Viscosity	
	@ 23°C(gm/cc)	@ 26.6°C	@ 23°C	@ 26.6°C
Native Crude	0.9330	0.9272	205 cp	139 cp
Dry Crude	0.9394	0.9335	992 cp	819 cp
Dry Crude + Heptane	0.9161	0.9103	104 cp	74 cp

For the crude received from the field (Native crude):

Wt % water present = 6.0

Surface tension = 3.5 dynes/cm @ 23°C

B.S.&W = 10.0%

Acid Number = 0.527 mg KOH/gm crude

Asphaltene content = 6.06%

APPENDIX B

COMSUMPTION OF SODIUM HYDROXIDE BY WATER, SAND AND OIL

1. Consumption of Sodium Hydroxide by Native Water In The Form of Precipitation of Insoluble Compounds

When sodium hydroxide is added either to native water or source water, a definite amount will be consumed by the polyvalent ions in the water by chemical reaction and precipitation.

Native water contains a large amount of polyvalent ions (Table A-3, Appendix A) and accordingly will consume more sodium hydroxide than source water.

In the following calculation, the reaction between sodium hydroxide and native water is considered.

The polyvalent ions present in native water are:

	Anions	Cations	
(Sulfate)	SO_4^{--}	Ca^{++}	(Calcium)
(Chloride)	Cl^-	Mg^{++}	(Magnesium)
(Nitrate)	NO_3^-	Na^+	(Sodium)
(Carbonate)	CO_3^{--}	K^+	(Potassium)
(Bicarbonate)	HCO_3^-		

The ions which will react readily with sodium hydroxide are bicarbonate ion, HCO_3^- and magnesium ion, Mg^{++}. Calcium ion, Ca^{++} will react less readily with sodium hydroxide.

The process of the reactions:

(1) Sodium ions will form when sodium hydroxide is dissolved in water

$$NaOH + H_2O \longrightarrow Na^+ + OH^- + H_2O$$

(2) Reaction between the hydroxyl ions and the other ions will take place

$$OH^- + HCO_3^- \longrightarrow H_2O + CO_3^{--}$$

$$2OH^- + Mg^{++} \longrightarrow Mg(OH)_2$$

(magnesium hydroxide)

$$2OH^- + Ca^{++} \longrightarrow Ca(OH)_2$$

(calcium hydroxide)

In a typical water analysis (Table A-3) there is 1423 ppm of Mg^{++}, or $\frac{1423 \text{ mg } Mg^{++}}{1000 \text{ g of water}}$

Atomic Weight of Mg^{++} = 24.3 gm

$$\text{The molality of } Mg^{++} = 1.423 \text{ gm} \times \frac{1 \text{ mol}}{24.3 \text{ gm}}$$

$$= 0.058 \text{ M } Mg^{++}$$

The solubility product K_{sp} of $Mg(OH)_2$ is 1×10^{-11} at $20^{o}C$

If 500 ml of 0.25 wt % sodium hydroxide is added to 500 ml of the above water with 0.058 M Mg^{++}:

Since 1 M of sodium hydroxide is 1 mole NaOH/1000 g solvent and is approximately 3.8 weight percent of sodium hydroxide in water

Therefore, 0.25 wt % NaOH is approximately equivalent to 0.065 M

$$Mg(OH)_2 \longrightarrow Mg^{++} + 2OH^{-}$$

$$K_{sp} = 1 \times 10^{-11} \text{ at } 20^{o}C$$

$$K_{sp} = (Mg^{++})\ (OH^{-})^2$$

In this case, $(0.058)\ (0.065)^2 = 2.450 \times 10^{-4}$

$2.450 \times 10^{-4} > 1 \times 10^{-11}$, a precipitate will be formed. For $Mg(OH)_2$ not to be formed, $(Mg^{++})\ (OH^{-})^2$ should be less than or equal to 1×10^{-11}

The least amount of sodium hydroxide (0.25 wt %) needed to react with the magnesium ions.

$$(Mg^{++}) = \frac{1 \times 10^{-11}}{(0.065)^2} = 2.366 \times 10^{-9} \ \frac{\text{mols}}{\text{litre}}$$

For K_{sp} to be equal to 1×10^{-11}, using a sodium hydroxide solution of 0.065 M (OH^-), the (Mg^{++}) would have to be reduced to $2.366 \times 10^{-9} \ \frac{\text{mols}}{\text{litre}}$. In other words all the (Mg^{++}) in the water will react with any sodium hydroxide added. For a full reaction to take place, 2 x (Mg^{++}) of (OH^-) will be needed. Therefore, to consume 1423 ppM of mg^{++}

$$2 \times \frac{1.423 \text{ g/l}}{24.30 \text{ g/mole}} = 0.117 \ \frac{\text{mol}}{\text{l}} \text{ of } (OH^-) \text{ is needed}$$

The same procedure may be repeated for the bicarbonate ion

$$HCO_3^- + OH^- \rightarrow CO_3^{--} + H_2O$$

One bicarbonate ion will react with one hydroxyl ion

Since there are 81.1 ppM of HCO_3^-

or $$81.1 \ \frac{\text{mg}}{1000 \text{ g solution}} = \frac{0.0811 \text{ g/l}}{61.02 \text{ g/mol}} = 1.33 \times 10^{-3} \ \frac{\text{mol}}{\text{l}}$$

An equivalent amount of NaOH, ie $1.33 \times 10^{-3} \ \frac{\text{mol}}{\text{l}}$ will be required to react entirely with HCO_3^-

Repeating the procedure for Ca^{++}

Concentration of Ca^{++} is 2722.7 $\frac{mg}{l}$

$$= \frac{\frac{2.7227}{40.08}\ \frac{mol}{l}}{}$$

$$(Ca^{++}) = 0.0679\ \frac{mol}{l}$$

The solubility of $Ca(OH)_2$ at 20^oC is

1.65×10^{-1} gm/100 gm solution

or $1.65 \times 10^{-1}\ \frac{gm}{100\ ml} \times \frac{1\ mol}{40.08\ gm} \times \frac{1000\ ml}{1\ l}$

$$= 0.0411\ \frac{moles}{l}$$

$$Ca(OH)_2 \rightarrow Ca^{++} + 2OH^-$$

The concentration of (OH^-) is twice that of Ca^{++} or $(OH^-) = 2(Ca^{++}) = 0.0822\ \frac{moles}{l}$

$$K_{sp} = (Ca^{++})\ (OH^-)^2 = (0.0411)\ (0.0822)^2$$

$$K_{sp} = 2.781 \times 10^{-4} \text{ at } 20^oC$$

Suppose 500 ml of 0.25 wt % NaOH is added to 500 ml of 0.0679 M Ca^{++}

0.25 wt % NaOH = 0.065 M

$K_{sp} = (Ca^{++})\ (OH^{-})^2 = 2.781 \times 10^{-4}$

now $(0.0679)\ (0.065)^2 = 2.652 \times 10^{-4}$

This is more than K_{sp} so precipitate will form.

TABLE B-1

CONSUMPTION OF SODIUM HYDROXIDE BY VIKING KINSELLA SAND
USED IN 1½" DIAMETER CORES

Original NaOH Concentration (wt %)	CONCENTRATION OF NaOH (wt %) AS A FUNCTION OF ELAPSED TIME		
	After 24 hrs.	After 48 hrs.	After 192 hrs.
2.0	1.91	1.93	1.94
4.0	3.95	3.91	3.96
6.0	6.0	5.95	5.99
8.0	7.44	7.5	7.5
10.0	9.1	9.1	9.1

APPENDIX C

PHYSICAL PROPERTIES AND INITIAL CONDITIONS OF CORE PACKS

TABLE C-1

Physical Properties of Cores

Core #	Run #	Sand	Pore Volume (cc)	Bulk Volume (cc)	Porosity Ø (%)	Absolute Permeability K (md)
1	1,12	#1	894.0	2103.5	42.5	243.0
2	2,13	#1	870.72	2022.1	43.06	364.2
3	3,14	#1	886.9	2072.2	42.8	373.0
4	5,16	#2	495.25	1076.63	46.0	209.16
5	6,7,9,19	#2	485.27	1078.38	45.0	258.5
6	8,17,18	#2	484.32	1076.27	45.0	260.58
7	10,11,21	#3	420.15	1086.5	38.67	1550.0
8	20	#3	417.3	1077.46	38.73	1530.0
9	15	#1	894.72	2023.8	44.21	457.0
10	22	#3	436.78	1087.6	40.16	62.9

* Sand

#1 Clean Viking Kinsella

#2 Silty Viking Kinsella

#3 Saskatchewan Sand

TABLE C-2

Initial Conditions of Cores

Core #	Run #	Type of Flood	Initial Water in Place cc (% pv)		Initial Oil in Place cc (% pv)		
1	1	Water	189.3	0.21	704.7	0.79	
	12	NaOH	123.3	0.14	770.7	0.86	
2	2	Water	183.12	0.21	687.6	0.79	
	13	NaOH	152.92	0.18	717.8	0.82	
3	3	Water	196.40	0.22	690.5	0.78	
	14	NaOH	165.90	0.19	721.0	0.81	
4	5	Water	106.75	0.22	388.52	0.78	
	16	NaOH	97.63	0.20	397.62	0.80	
	6	Water	97.16	0.20	388.12	0.80	
5	7	Water	63.50	0.13	421.77	0.87	
	9	Water	66.45	0.14	418.82	0.86	
	19	NaOH	75.20	0.15	410.07	0.85	
	8	Water	97.13	0.20	387.36	0.80	
6	17	NaOH	98.36	0.20	484.32	0.80	
	18	NaOH	102.86	0.21	381.46	0.79	
7	10	Water	82.77	0.20	337.38	0.80	
	11	Water	55.32	0.13	364.83	0.87	* Heavy Crude
	21	NaOH	99.07	0.24	321.08	0.76	* Heavy Crude
8	20	NaOH	68.56	0.16	348.74	0.84	
9	15	NaOH	211.12	0.24	683.60	0.76	
10	21	NaOH	84.98	0.19	351.80	0.81	

APPENDIX D

SUMMARY OF WATERFLOOD DATA FROM INDIVIDUAL DISPLACEMENT TESTS

TABLE D 1.

CORE 1.

RUN 1.

CORE PROPERTIES

POROSITY	= 42.50	PERCENT
PERMEABILITY	=243.00	MD
PORE VOLUME	=894.00	CC
INITIAL WATER SAT.	=189.30	CC
INITIAL OIL IN PLACE	=704.70	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.57	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
	17.00	17.00	2.41			0.02			
127.00	23.50	40.50	5.75			0.05			
	22.00	62.50	8.87			0.07			
110.00	78.00	140.50	19.94	10.20	10.20	0.17		0.13	40239.00
	13.00	153.50	21.78	8.00	18.20	0.19	5.69	0.62	27831.00
	33.50	187.00	26.54	31.50	49.70	0.26		0.94	20090.00
	10.50	197.50	28.03	13.50	63.20	0.29	6.31	1.29	16530.00
	24.50	222.00	31.50	40.00	103.20	0.36		1.63	
	7.00	229.00	32.50	15.00	118.20	0.39	6.42	2.14	13472.00
	17.00	246.00	34.91	48.50	166.70	0.46		2.85	
	4.00	250.00	35.48	18.00	184.70	0.49	6.51	4.50	12728.00
60.00	14.00	264.00	37.46	96.50	281.20	0.61		6.89	12160.00
	3.00	267.00	37.89	20.00	301.20	0.64	6.71	6.67	12160.00
	9.00	276.00	39.17	80.00	381.20	0.74		8.89	
	2.50	278.50	39.52	19.50	400.70	0.76		7.80	11593.00
	2.00	280.50	39.80	20.50	421.20	0.78	6.90	10.25	10175.00
	9.50	290.00	41.15	102.00	523.20	0.91		10.74	8792.00
	1.50	291.50	41.37	20.50	543.70	0.93	7.05	13.67	
56.00	7.00	298.50	42.36	104.50	648.20	1.06		14.93	6523.00
	1.50	300.00	42.57	20.50	668.70	1.08	7.22	13.67	4751.00
	7.00	307.00	43.56	102.00	770.70	1.21		14.57	
	1.50	308.50	43.78	20.50	791.20	1.23	7.35	13.67	
	6.00	314.50	44.63	103.00	894.20	1.35		17.17	3191.00
	1.00	315.50	44.77	21.00	915.20	1.38	7.55	21.00	
	4.50	320.00	45.41	105.50	1020.70	1.50		23.44	1418.00
	0.50	320.50	45.48	22.00	1042.70	1.52	7.82	44.00	
50.00	1.00	321.50	45.62	41.00	1083.70	1.57		41.00	

TABLE D 2.

CORE 2.

RUN 2.

CORE PROPERTIES

POROSITY	= 43.06	PERCENT
PERMEABILITY	=364.20	MD
PORE VOLUME	=870.72	CC
INITIAL WATER SAT.	=183.12	CC
INITIAL OIL IN PLACE	=687.60	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.70	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
	25.00	25.00	3.64			0.03			
29.00	44.00	69.00	10.03	17.50	17.50	0.10	6.56	0.40	29249.00
	8.00	77.00	11.20	12.50	30.00	0.12		1.56	
	26.00	103.00	14.98	63.50	93.50	0.23		2.44	12054.00
	7.50	110.50	16.07	22.50	116.00	0.26	6.66	3.00	
	13.00	123.50	17.96	47.00	163.00	0.33		3.62	8213.00
	18.50	142.00	20.65	70.50	233.50	0.43		3.81	
25.00	5.50	147.50	21.45	24.50	258.00	0.47	6.85	4.45	7197.00
	17.00	164.50	23.92	74.00	332.00	0.57		4.35	
	10.50	175.00	25.45	51.50	383.50	0.64		4.90	6098.00
	4.50	179.50	26.11	21.50	405.00	0.67	7.04	4.78	
	12.00	191.50	27.85	77.00	482.00	0.77		6.42	5672.00
	8.50	200.00	29.09	50.00	532.00	0.84		5.88	
	3.50	203.50	29.60	26.50	558.50	0.88	7.10	7.57	5259.00
23.00	7.50	211.00	30.69	51.50	610.00	0.94		6.87	
	3.50	214.50	31.20	26.50	636.50	0.98		7.57	
	8.00	222.50	32.36	52.50	689.00	1.05		6.56	5023.00
23.00	4.00	226.50	32.94	25.50	714.50	1.08	7.21	6.38	
23.00	11.00	237.50	34.54	79.50	794.00	1.18		7.23	4924.00
	6.00	243.50	35.41	55.50	849.50	1.26		9.25	
	3.00	246.50	35.85	27.50	877.00	1.29	7.42	9.17	4766.00
	7.50	254.00	36.94	83.50	960.50	1.39		11.13	
	4.50	258.50	37.59	55.50	1016.00	1.46		12.33	4629.00
	2.00	260.50	37.89	27.50	1043.50	1.50	7.67	13.75	
22.00	9.00	269.50	39.19	129.00	1172.50	1.66		14.33	4176.00
	2.00	271.50	39.49	33.00	1205.50	1.70	7.85	16.50	3871.00

TABLE D 3.

CORE 3.

RUN 3.

CORE PROPERTIES

POROSITY	= 42.80	PERCENT
PERMEABILITY	=373.00	MD
PORE VOLUME	=886.90	CC
INITIAL WATER SAT.	=196.40	CC
INITIAL OIL IN PLACE	=690.50	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.46	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
	31.00	31.00	4.49			0.03			
27.00	36.00	67.00	9.70	29.50	29.50	0.11		0.82	31287.00
	10.00	77.00	11.15	23.00	52.50	0.15	6.50	2.30	
	17.50	94.50	13.69	47.00	99.50	0.22		2.69	11424.00
	22.00	116.50	16.87	76.50	176.00	0.33		3.48	
	7.00	123.50	17.89	25.50	201.50	0.37	6.81	3.64	8970.00
	20.00	143.50	20.78	79.50	281.00	0.48		3.97	
23.00	14.00	157.50	22.81	55.50	336.50	0.56		3.96	8787.00
	5.50	163.00	23.61	27.00	363.50	0.59	7.20	4.91	
	12.50	175.50	25.42	54.00	417.50	0.67		4.32	7485.00
	12.50	188.00	27.23	53.50	471.00	0.74		4.28	
	6.00	194.00	28.10	27.00	498.00	0.78	7.52	4.50	
	18.00	212.00	30.70	81.00	579.00	0.89		4.50	6598.00
	8.50	220.50	31.93	57.50	636.50	0.97		6.76	
	3.50	224.00	32.44	29.50	666.00	1.00	7.81	8.43	
21.00	5.50	229.50	33.24	60.50	726.50	1.08		11.00	6618.00
	3.50	233.00	33.74	30.00	756.50	1.12	8.10	8.57	
	8.00	241.00	34.90	92.50	849.00	1.23		11.56	6441.00
	7.00	248.00	35.92	92.50	941.50	1.34		13.21	5633.00
	2.50	250.50	36.28	31.00	972.50	1.38	8.27	12.40	
21.00	6.00	256.50	37.15	66.00	1038.50	1.46		11.00	

TABLE D 4

CORE 4.

RUN 5.

CORE PROPERTIES			EXPERIMENTAL VARIABLES		
POROSITY	= 46.00	PERCENT	RATE OF INJECTION	=12.00	CC/HR
PERMEABILITY	=209.16	MD	SLUG SIZE OF WATER	= 1.69	PV
PORE VOLUME	=495.25	CC	SLUG SIZE NAOH	=	PV
INITIAL WATER SAT.	=106.75	CC	CONCENTRATION NAOH	=	WT-PC
INITIAL OIL IN PLACE	=388.52	CC	TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
	21.00	21.00	5.41			0.04			
	20.50	41.50	10.68	4.50	4.50	0.09		0.22	17549.00
	12.50	54.00	13.90	12.50	17.00	0.14		1.00	14624.00
	9.00	63.00	16.22	16.00	33.00	0.19		1.78	13738.00
	10.00	73.00	18.79	15.00	48.00	0.24		1.50	14181.00
	10.50	83.50	21.49	15.00	63.00	0.30		1.43	15599.00
	9.00	92.50	23.81	15.50	78.50	0.35		1.72	15067.00
	9.50	102.00	26.25	15.00	93.50	0.39		1.58	14181.00
	7.00	109.00	28.06	17.00	110.50	0.44		2.43	
	8.00	117.00	30.11	16.00	126.50	0.49		2.00	
	7.00	124.00	31.92	18.00	144.50	0.54		2.57	12940.00
	4.00	128.00	32.95	21.00	165.50	0.59		5.25	
	5.00	133.00	34.23	20.00	185.50	0,64		4.00	
	4.50	137.50	35.39	21.50	207.00	0.70		4.78	
	3.00	140.50	36.16	22.00	229.00	0.75		7.33	
	2.00	142.50	36.68	23.00	252.00	0.80		11.50	12408.00
	1.50	144.00	37.06	24.00	276.00	0.85		16.00	
	2.00	146.00	37.58	23.00	299.00	0.90		11.50	
	2.00	148.00	38.09	22.00	321.00	0.95		11.00	
	2.00	150.00	38.61	23.00	344.00	1.00		11.50	7711.00
	1.50	151.50	38.99	23.00	367.00	1.05		15.33	3849.00
	1.50	153.00	39.38	23.50	390.50	1.10		15.67	
	3.50	156.50	40.28	12.00	402.50	1.13		3.43	
	1.50	158.00	40.67	24.00	426.50	1.18		16.00	
	2.00	160.00	41.18	24.00	450.50	1.23		12.00	2639.00
	3.00	163.00	41.95	23.00	473.50	1.29		7.67	
	1.50	164.50	42.34	24.50	498.00	1.34		16.33	
	1.50	166.00	42.73	23.50	521.50	1.39		15.67	
	1.00	167.00	42.98	25.00	546.50	1.44		25.00	1496.00
	8.50	175.50	45.17	116.50	663.00	1.69		13.71	

TABLE D 5

CORE 5.

RUN 6.

CORE PROPERTIES			EXPERIMENTAL VARIABLES		
POROSITY	= 45.00	PERCENT	RATE OF INJECTION	=12.00	CC/HR
PERMEABILITY	=258.50	MD	SLUG SIZE OF WATER	= 1.48	PV
PORE VOLUME	=485.27	CC	SLUG SIZE NAOH	=	PV
INITIAL WATER SAT.	= 97.16	CC	CONCENTRATION NAOH	=	WT-PC
INITIAL OIL IN PLACE	=388.12	CC	TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
95.00	7.50	7.50	1.93			0.02			
95.00	25.00	32.50	8.37			0.07			
90.00	19.00	51.50	13.27	6.00	6.00	0.12		0.32	20917.00
90.00	12.00	63.50	16.36	13.00	19.00	0.17	7.85	1.08	
80.00	9.00	72.50	18.68	15.00	34.00	0.22	7.79	1.67	13028.00
80.00	8.00	80.50	20.74	16.00	50.00	0.27		2.00	
	7.00	87.50	22.54	17.50	67.50	0.32		2.50	
	6.50	94.00	24.22	18.00	85.50	0.37		2.77	
	5.50	99.50	25.64	19.00	104.50	0.42	7.75	3.45	11061.00
70.00	5.00	104.50	26.92	19.00	123.50	0.47		3.80	
65.00	4.00	108.50	27.96	20.00	143.50	0.52		5.00	
	5.00	113.50	29.24	20.00	163.50	0.57		4.00	
	3.50	117.00	30.15	22.00	185.50	0.62	7.68	6.29	11522.00
	3.50	120.50	31.05	22.00	207.50	0.68		6.29	
50.00	3.00	123.50	31.82	22.00	229.50	0.73		7.33	
	3.00	126.50	32.59	22.00	251.50	0.78		7.33	
	2.50	129.00	33.24	21.00	272.50	0.83	8.16	8.40	9084.00
50.00	3.00	132.00	34.01	22.00	294.50	0.88		7.33	
	2.00	134.00	34.53	22.00	316.50	0.93		11.00	
45.00	1.00	135.00	34.78	22.00	338.50	0.98		22.00	
45.00	2.00	137.00	35.30	22.00	360.50	1.03	8.28	11.00	6854.00
	2.00	139.00	35.81	23.00	383.50	1.08		11.50	
	1.00	140.00	36.07	24.00	407.50	1.13		24.00	
20.00	2.50	142.50	36.72	23.00	430.50	1.18		9.20	
20.00	2.00	144.50	37.23	24.00	454.50	1.23		12.00	
	8.50	153.00	39.42	112.00	566.50	1.48	8.26	13.18	5317.00

TABLE D 6.

CORE 5.

RUN 7.

CORE PROPERTIES			EXPERIMENTAL VARIABLES		
POROSITY	= 45.00	PERCENT	RATE OF INJECTION	=12.00	CC/HR
PERMEABILITY	=258.50	MD	SLUG SIZE OF WATER	= 1.83	PV
PORE VOLUME	=485.27	CC	SLUG SIZE NAOH	=	PV
INITIAL WATER SAT.	= 63.50	CC	CONCENTRATION NAOH	=	WT-PC
INITIAL OIL IN PLACE	=421.77	CC	TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
100.00	12.50	12.50	2.96			0.03			
100.00	22.50	35.00	8.30			0.07			
90.00	16.50	51.50	12.21			0.11			
88.00	11.50	63.00	14.94			0.13			
	12.20	75.20	17.83	1.80	1.80	0.16	7.18	0.15	45202.00
	23.50	98.70	23.40	15.00	16.80	0.24		0.64	
	6.50	105.20	24.94	8.50	25.30	0.27	7.34	1.31	28835.00
	15.50	120.70	28.62	28.00	53.30	0.36	7.37	1.81	
	4.00	124.70	29.57	10.50	63.80	0.39		2.63	24108.00
	17.50	142.20	33.72	78.50	142.30	0.59	7.72	4.49	
50.00	3.00	145.20	34.43	27.00	169.30	0.65		9.00	13826.00
	5.00	150.20	35.61	30.00	199.30	0.72	7.66	6.00	
45.00	5.00	155.20	36.80	20.00	219.30	0.77		4.00	10813.00
	14.50	169.70	40.24	86.00	305.30	0.98		5.93	
	2.50	172.20	40.83	22.00	327.30	1.03	8.18	8.80	6647.00
20.00	2.00	174.20	41.30	22.00	349.30	1.08	8.10	11.00	6027.00
	5.00	179.20	42.49	73.00	422.30	1.24		14.60	
20.00	1.50	180.70	42.84	30.50	452.80	1.31	8.10	20.33	3994.00
	4.50	185.20	43.91	66.50	519.30	1.45		14.78	
20.00	1.00	186.20	44.15	28.00	547.30	1.51	8.09	28.00	3052.00
	3.00	189.20	44.86	41.00	588.30	1.60		13.67	
	1.00	190.20	45.10	22.50	610.80	1.65	8.14	22.50	2180.00
	3.50	193.70	45.93	67.50	678.30	1.80		19.29	
20.00	1.00	194.70	46.16	15.00	693.30	1.83	8.00	15.00	2127.00

TABLE D 7.

CORE 6.

RUN 8.

CORE PROPERTIES

POROSITY	= 45.00	PERCENT
PERMEABILITY	=260.58	MD
PORE VOLUME	=484.32	CC
INITIAL WATER SAT.	= 97.13	CC
INITIAL OIL IN PLACE	=387.36	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 1.79	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
100.00	37.00	37.00	9.55			0.08			
	7.00	44.00	11.36	4.00	4.00	0.10	7.60	0.57	28000.00
50.00	16.50	60.50	15.62	10.00	14.00	0.15		0.61	27200.00
	13.50	74.00	19.10	13.50	27.50	0.21	7.79	1.00	18900.00
	9.50	83.50	21.56	16.50	44.00	0.26		1.74	16500.00
	9.50	93.00	24.01	17.50	61.50	0.32	7.66	1.84	15400.00
36.00	9.00	102.00	26.33	18.00	79.50	0.37		2.00	13000.00
	8.50	110.50	28.53	24.00	103.50	0.44	7.35	2.82	12400.00
	7.50	118.00	30.46	21.00	124.50	0.50	7.47	2.80	
30.00	18.00	136.00	35.11	85.50	210.00	0.71		4.75	10281.00
	2.50	138.50	35.75	13.50	223.50	0.75	7.70	5.40	
	5.50	144.00	37.17	35.00	258.50	0.83		6.36	
	3.50	147.50	38.08	10.50	269.00	0.86	7.69	3.00	8567.00
20.00	6.00	153.50	39.63	35.00	304.00	0.94		5.83	
	1.00	154.50	39.89	13.00	317.00	0.97	7.48	13.00	6989.00
	9.00	163.50	42.21	52.00	369.00	1.10		5.78	
	2.50	166.00	42.85	29.00	398.00	1.16	7.48	11.60	5200.00
20.00	5.50	171.50	44.27	104.00	502.00	1.39		18.91	
	1.00	172.50	44.53	12.50	514.50	1.42	8.24	12.50	3190.00
	2.60	175.10	45.20	36.90	551.40	1.50		14.19	
	1.00	176.10	45.46	12.00	563.40	1.53	8.03	12.00	2600.00
15.00	3.50	179.60	46.37	36.00	599.40	1.61		10.29	
	1.00	180.60	46.62	12.50	611.90	1.64	7.93	12.50	2000.00
	4.00	184.60	47.66	68.50	680.40	1.79		17.13	

TABLE D 8.

CORE 5.

RUN 9.

CORE PROPERTIES

POROSITY	= 45.00	PERCENT
PERMEABILITY	=258.50	MD
PORE VOLUME	=485.27	CC
INITIAL WATER SAT.	= 66.45	CC
INITIAL OIL IN PLACE	=418.82	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=50.00	CC/HR
SLUG SIZE OF WATER	= 2.10	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
						0.11			
554.00	51.00	51.00	12.18			0.18		0.08	
600.00	32.50	83.50	19.94	2.50	2.50	0.25	7.94	0.39	32794.00
528.00	24.50	108.00	25.79	9.50	12.00	0.32		1.13	
490.00	16.00	124.00	29.61	18.00	30.00	0.39		1.83	
420.00	12.00	136.00	32.47	22.00	52.00	0.46		3.25	
	8.00	144.00	34.38	26.00	78.00	0.53	7.85	5.18	27771.00
	5.50	149.50	35.70	28.50	106.50	0.60		6.44	
	4.50	154.00	36.77	29.00	135.50	0.67		7.50	
	4.00	158.00	37.73	30.00	165.50	0.74		5.18	
	5.50	163.50	39.04	28.50	194.00	0.81	7.85	10.33	8626.00
	3.00	166.50	39.75	31.00	225.00	0.88		12.40	
	2.50	169.00	40.35	31.00	256.00	0.94		21.33	
	1.50	170.50	40.71	32.00	288.00	1.01		21.33	
	1.50	172.00	41.07	32.00	320.00	1.08	7.98	16.00	4301.00
	2.00	174.00	41.55	32.00	352.00	1.15		10.33	
	3.00	177.00	42.26	31.00	383.00	1.22		12.60	
	2.50	179.50	42.86	31.50	414.50	1.29		12.60	
	2.50	182.00	43.46	31.50	446.00	1.36		16.00	
	2.00	184.00	43.93	32.00	478.00	1.43		21.67	
	1.50	185.50	44.29	32.50	510.50	1.50		16.00	
	2.00	187.50	44.77	32.00	542.50	1.57	8.18	21.67	1418.00
130.00	1.50	189.00	45.13	32.50	575.00	1.64		12.60	
130.00	2.50	191.50	45.72	31.50	606.50	1.71		16.00	
	2.00	193.50	46.20	32.00	638.50	1.78		33.00	
	1.00	194.50	46.44	33.00	671.50	1.85	8.22	16.00	886.00
	2.00	196.50	46.92	32.00	703.50	2.10		18.75	
	6.00	202.50	48.35	112.50	816.00				

TABLE D 9.

CORE 7.

RUN 10.

CORE PROPERTIES			EXPERIMENTAL VARIABLES		
POROSITY	= 38.67	PERCENT	RATE OF INJECTION	=12.00	CC/HR
PERMEABILITY	= 1.55	D	SLUG SIZE OF WATER	= 1.84	PV
PORE VOLUME	=420.15	CC	SLUG SIZE NAOH	=	PV
INITIAL WATER SAT.	= 82.77	CC	CONCENTRATION NAOH	=	WT-PC
INITIAL OIL IN PLACE	=337.38	CC	TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
15.00	28.50	28.50	8.45			0.07			
15.00	28.50	57.00	16.89			0.14			
	41.50	98.50	29.20			0.23			
	21.00	119.50	35.42			0.28			
10.00	6.50	126.00	37.35	6.50	6.50	0.32	7.82	1.00	
10.00	5.00	131.00	38.83	21.00	27.50	0.38		4.20	
	1.50	132.50	39.27	11.50	39.00	0.41	7.98	7.67	36693.00
	5.50	138.00	40.90	33.50	72.50	0.50		6.09	
	3.00	141.00	41.79	11.00	83.50	0.53	8.10	3.67	23398.00
	4.00	145.00	42.98	22.00	105.50	0.60		5.50	
5.00	7.50	152.50	45.20	32.00	137.50	0.69		4.27	
	4.00	156.50	46.39	43.00	180.50	0.80	7.96	10.75	8508.00
	4.50	161.00	47.72	63.50	244.00	0.96		14.11	
	2.00	163.00	48.31	22.00	266.00	1.02		11.00	
	1.50	164.50	48.76	11.50	277.50	1.05	8.00	7.67	2304.00
	4.00	168.50	49.94	36.00	313.50	1.15		9.00	
	1.00	169.50	50.24	12.00	325.50	1.18	8.20	12.00	1654.00
	2.00	171.50	50.83	37.00	362.50	1.27		18.50	
	1.00	172.50	51.13	12.00	374.50	1.30	8.30	12.00	974.00
	3.00	175.50	52.02	28.00	402.50	1.38		9.33	
	2.00	177.50	52.61	34.00	436.50	1.46		17.00	
	4.50	182.00	53.95	37.50	474.00	1.56	8.30	8.33	
	1.00	183.00	54.24	19.00	493.00	1.61		19.00	
	0.50	183.50	54.39	38.50	531.50	1.70		77.00	
	1.00	184.50	54.69	21.00	552.50	1.75		21.00	
	1.00	185.50	54.98	35.00	587.50	1.84		35.00	

TABLE D 10

CORE 7.

RUN 11.

CORE PROPERTIES

POROSITY	= 38.67	PERCENT
PERMEABILITY	= 1.55	D
PORE VOLUME	=420.15	CC
INITIAL WATER SAT.	= 55.32	CC
INITIAL OIL IN PLACE	=364.83	CC

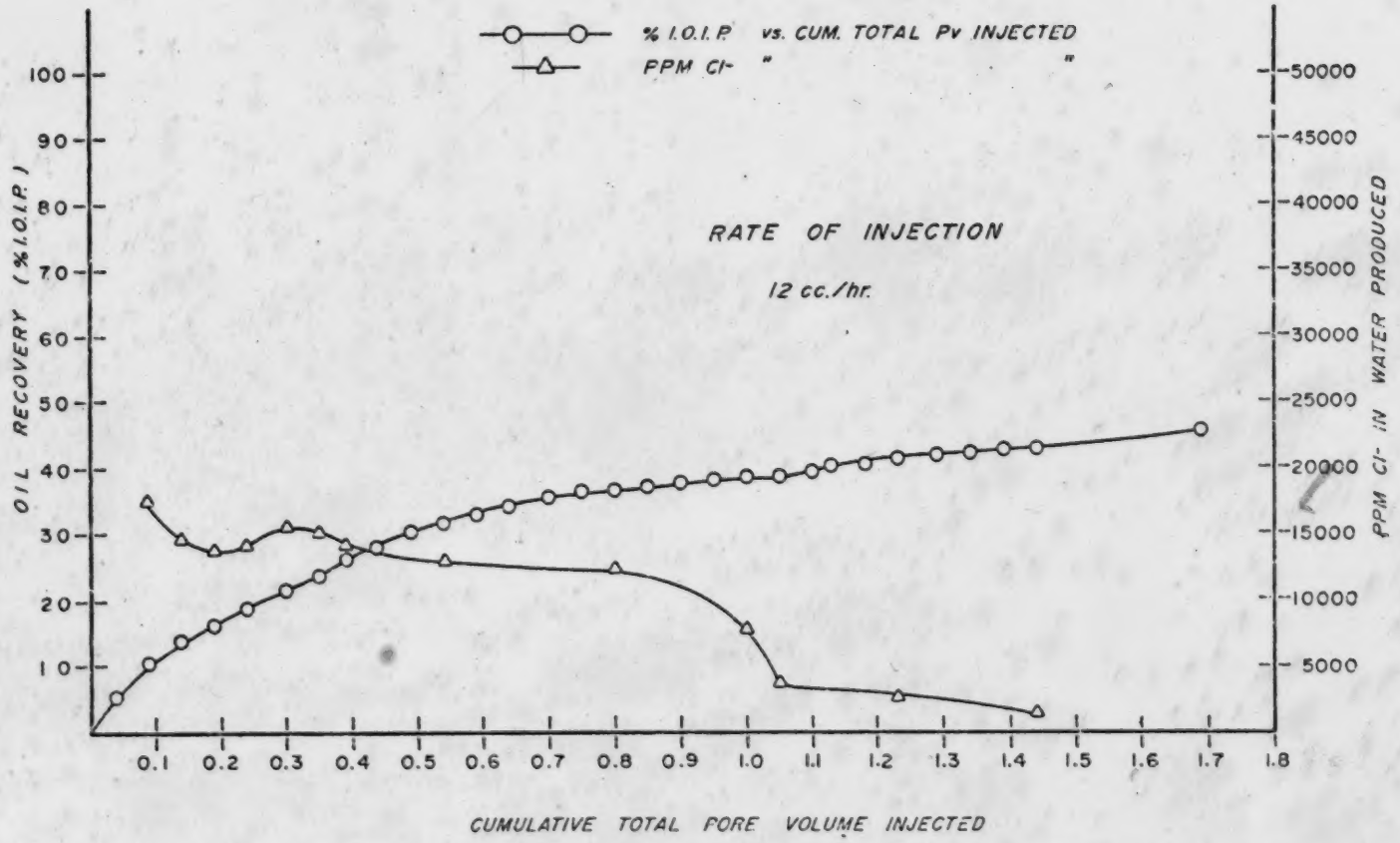
EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 1.93	PV
SLUG SIZE NAOH	=	PV
CONCENTRATION NAOH	=	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)
150.00	35.00	35.00	9.59			0.08			
100.00	12.75	47.75	13.09	0.25	0.25	0.11		0.02	
60.00	8.00	55.75	15.28	6.00	6.25	0.15	7.39	0.75	46089.00
	14.50	70.25	19.26	25.50	31.75	0.24		1.76	
	4.00	74.25	20.35	10.00	41.75	0.28	7.55	2.50	26590.00
30.00	11.00	85.25	23.37	48.00	89.75	0.42		4.36	
20.00	5.00	90.25	24.74	34.00	123.75	0.51		6.80	
20.00	4.00	94.25	25.83	28.00	151.75	0.59	7.82	7.00	6854.00
	4.00	98.25	26.93	52.00	203.75	0.72		13.00	
	3.00	101.25	27.75	33.00	236.75	0.80		11.00	
	6.00	107.25	29.40	19.00	255.75	0.86	8.06	3.17	2753.00
	5.50	112.75	30.90	35.50	291.25	0.96		6.45	
15.00	3.00	115.75	31.73	11.00	302.25	0.99	8.14	3.67	2265.00
	7.00	122.75	33.65	52.00	354.25	1.14		7.43	
	4.00	126.75	34.74	31.00	385.25	1.22		7.75	
	3.00	129.75	35.56	36.00	421.25	1.31		12.00	
	1.00	130.75	35.84	15.00	436.25	1.35		15.00	
	0.50	131.25	35.98	13.50	449.75	1.38	8.33	27.00	2000.00
15.00	3.50	134.75	36.93	37.50	487.25	1.48		10.71	
	2.50	137.25	37.62	36.50	523.75	1.57		14.60	
	1.50	138.75	38.03	37.50	561.25	1.67		25.00	
	1.00	139.75	38.31	12.00	573.25	1.70	8.37	12.00	1595.00
	4.00	143.75	39.40	51.00	624.25	1.83		12.75	
	2.50	146.25	40.09	40.50	664.75	1.93		16.20	

PERFORMANCE OF LABORATORY WATERFLOOD ON 1 1/2" DIAMETER

CORE NO. 4 RUN No. 5 (FIG. D - 1)



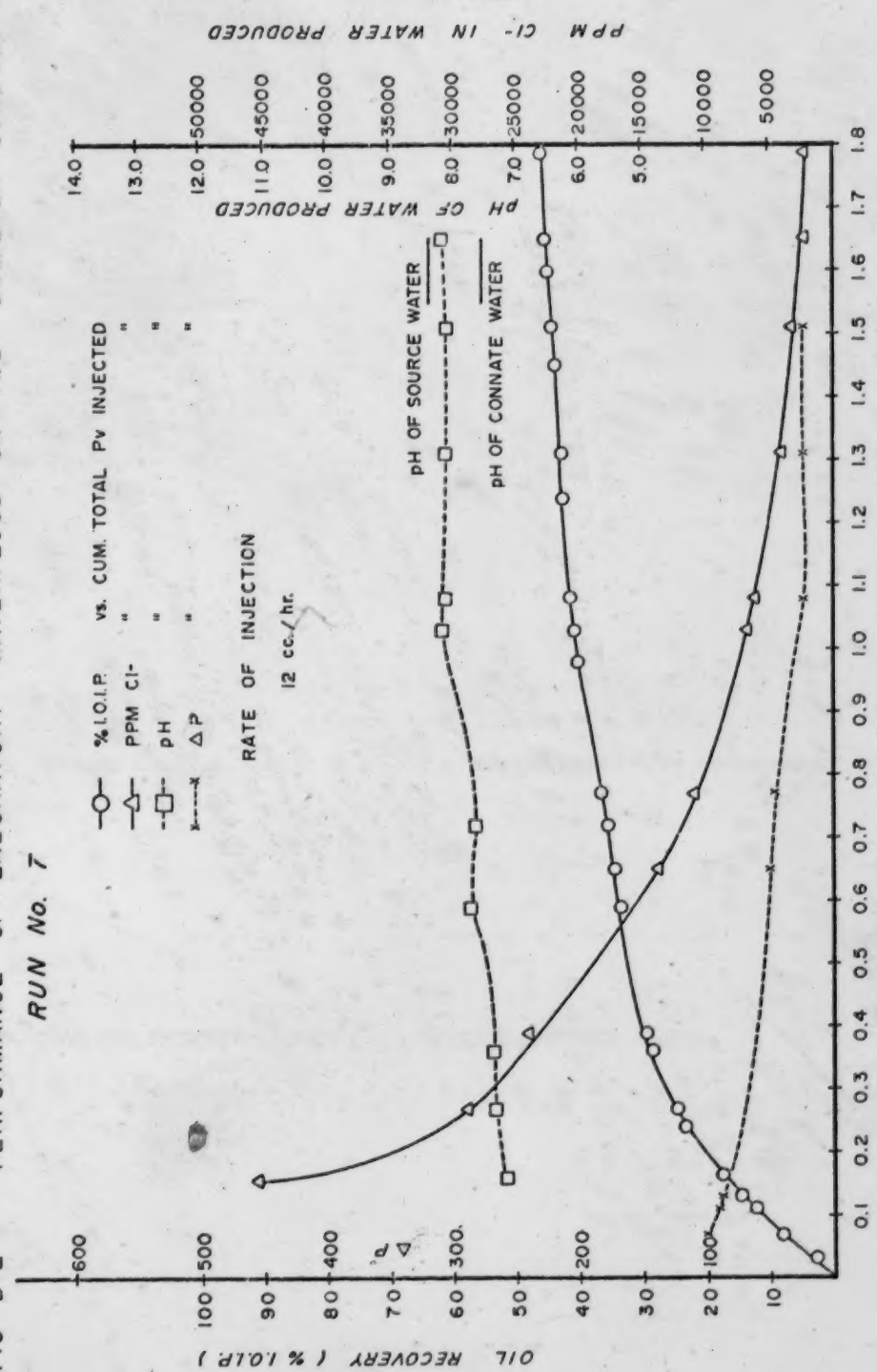
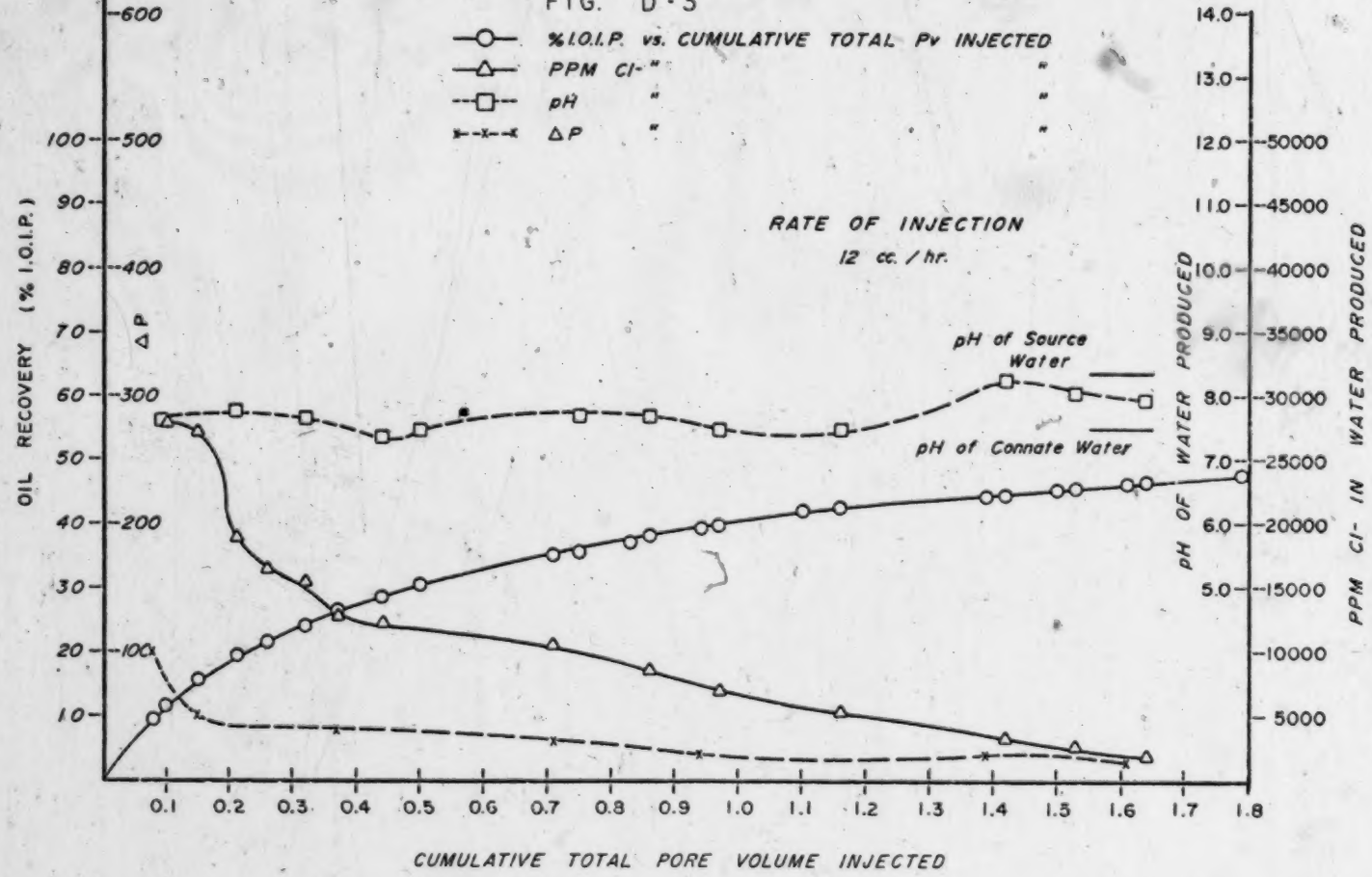


FIG D-2 PERFORMANCE OF LABORATORY WATERFLOOD ON 1 1/2" DIAMETER CORE No.5

PERFORMANCE OF LABORATORY WATERFLOOD ON 1 1/2" CORE NO. 6

RUN No. 8

FIG. D-3



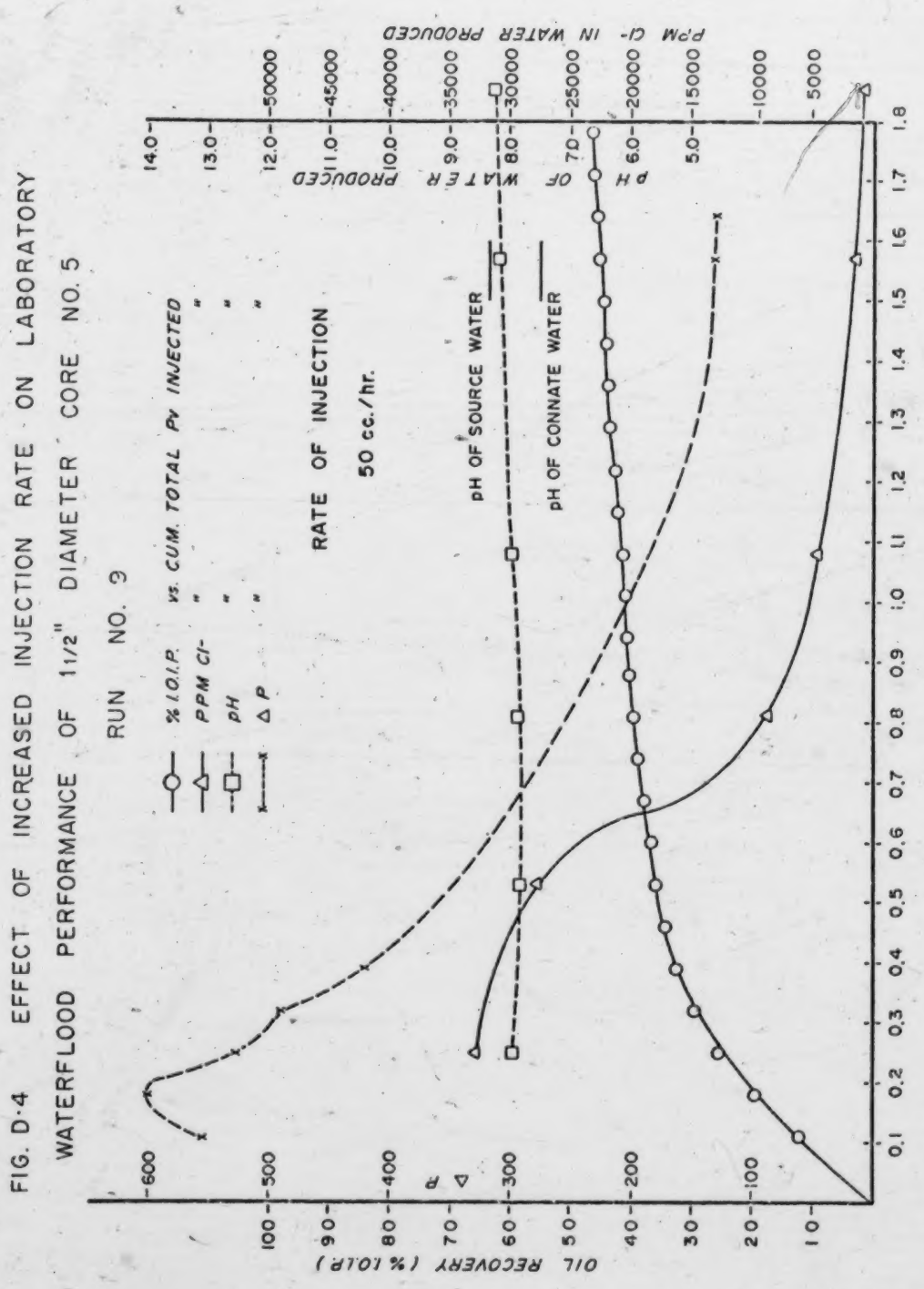


FIG. D·4 EFFECT OF INCREASED INJECTION RATE ON LABORATORY WATERFLOOD PERFORMANCE OF 1 1/2" DIAMETER CORE NO. 5

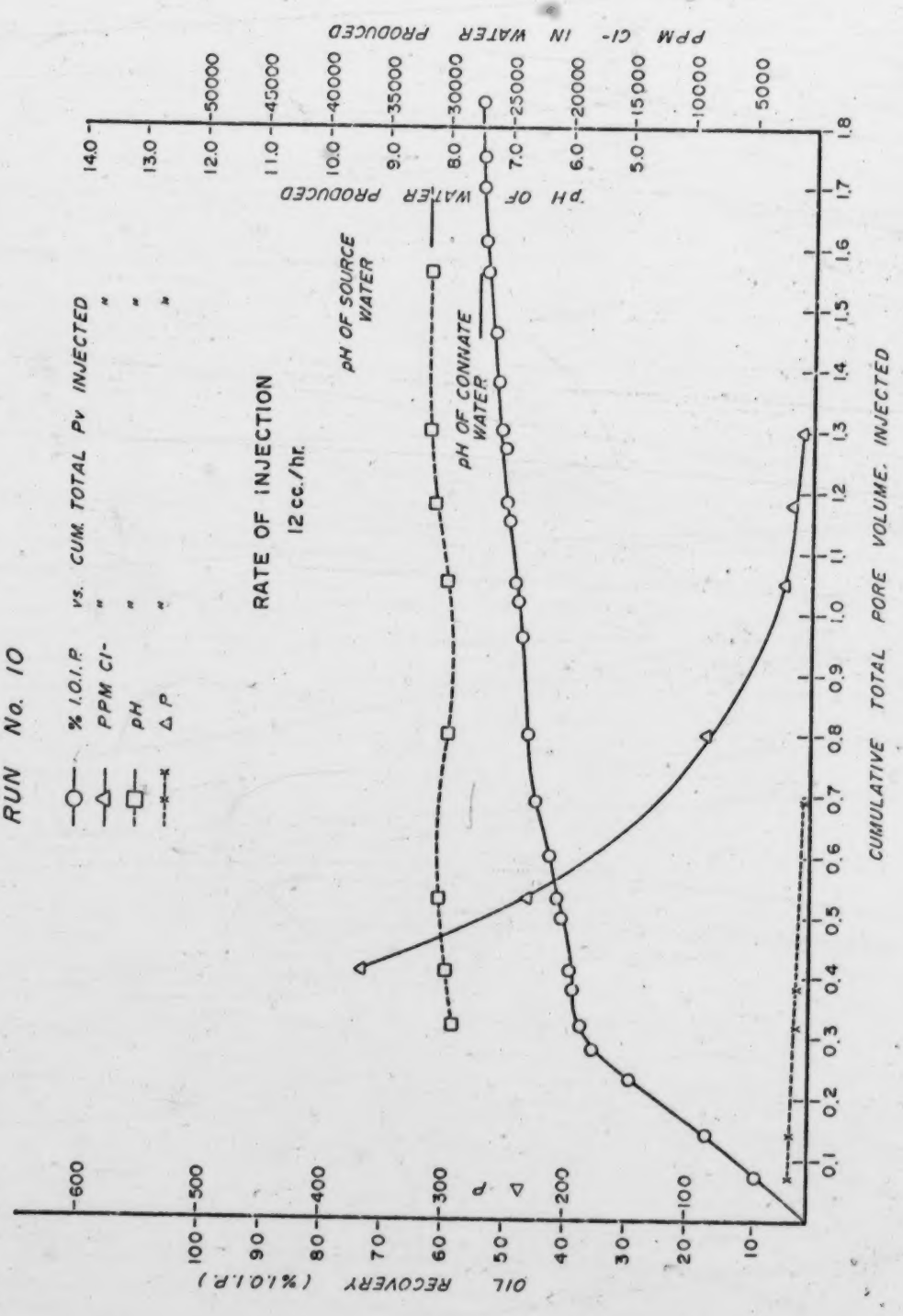

RUN No. 10
% I.O.I.P vs. CUM. TOTAL Pv INJECTED
PPM Cl- " "
pH " "
Δ P " "
RATE OF INJECTION
12 cc./hr.
pH OF SOURCE WATER
pH OF CONNATE WATER
pH OF WATER PRODUCED
PPM Cl- IN WATER PRODUCED
OIL RECOVERY (% I.O.I.P.)
CUMULATIVE TOTAL PORE VOLUME. INJECTED

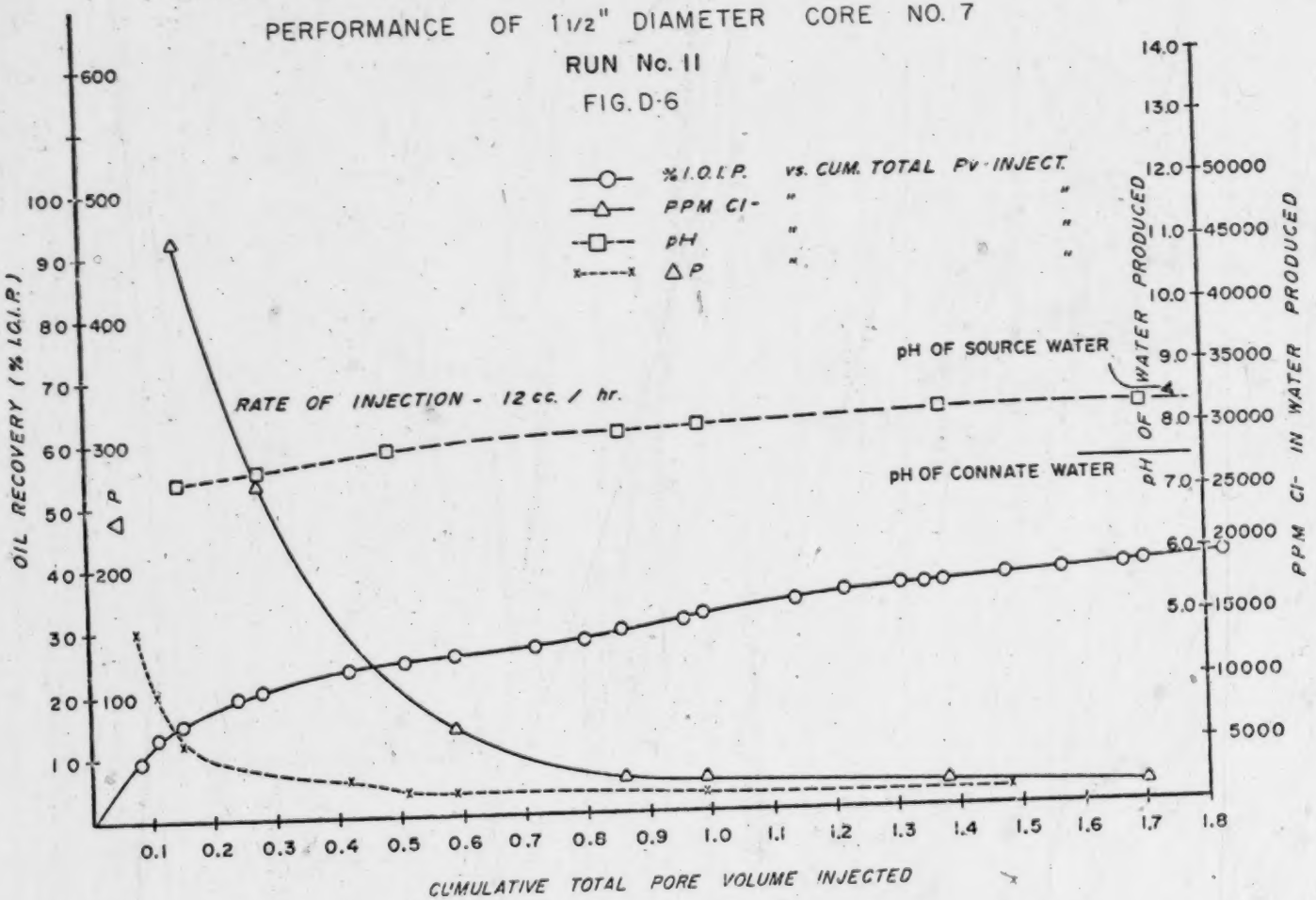
FIG. D-5 PERFORMANCE OF LABORATORY WATERFLOOD ON 1 1/2" CORE NO. 7

EFFECT OF UNDILUTED CRUDE ON LABORATORY WATERFLOOD

PERFORMANCE OF 1 1/2" DIAMETER CORE NO. 7

RUN No. II

FIG. D-6


% I.O.I.P. vs. CUM. TOTAL Pv INJECT.
PPM Cl⁻ " " "
pH " " "
ΔP " " "
RATE OF INJECTION - 12 cc. / hr.
pH OF SOURCE WATER
pH OF CONNATE WATER
OIL RECOVERY (% I.O.I.P.)
ΔP
pH OF WATER PRODUCED
PPM Cl⁻ IN WATER PRODUCED
CUMULATIVE TOTAL PORE VOLUME INJECTED
0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0 1.1 1.2 1.3 1.4 1.5 1.6 1.7 1.8
10 20 30 40 50 60 70 80 90 100
100 200 300 400 500 600
5.0 6.0 7.0 8.0 9.0 10.0 11.0 12.0 13.0 14.0
5000 10000 15000 20000 25000 30000 35000 40000 45000 50000

APPENDIX E

SUMMARY OF SODIUM HYDROXIDE FLOOD RESULTS

TABLE E 1.

CORE 1.

RUN 12.

CORE PROPERTIES

POROSITY	= 42.50	PERCENT
PERMEABILITY	=243.00	MD
PORE VOLUME	=894.00	CC
INITIAL WATER SAT.	=123.30	CC
INITIAL OIL IN PLACE	=770.70	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.59	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 2.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	31.50	31.50	4.09			0.04				
	29.50	61.00	7.91			0.07				
	29.10	90.10	11.69	0.40	0.40	0.10		0.01		
	45.10	135.20	17.54	12.40	12.80	0.17		0.27	42012.00	
	18.50	153.70	19.94	11.50	24.30	0.20	6.00	0.62	27476.00	
88.00	27.00	180.70	23.45	21.50	45.80	0.25		0.80		
92.00	13.00	193.70	25.13	16.00	61.80	0.29	6.54	1.23	18967.00	
132.00	45.00	238.70	30.97	76.00	137.80	0.42		1.69	16805.00	
	12.00	250.70	32.53	16.00	153.80	0.45	6.74	1.33	30844.00	
	75.00	325.70	42.26	68.50	222.30	0.61		0.91	21892.00	
	9.00	334.70	43.43	19.50	241.80	0.64	6.86	2.17	13945.00	
540.00	33.50	368.20	47.77	81.00	322.80	0.77		2.42		
890.00	7.00	375.20	48.68	23.00	345.80	0.81		3.29		
	6.50	381.70	49.53	23.50	369.30	0.84	6.94	3.62		
1000.00	14.50	396.20	51.41	69.50	438.80	0.93		4.79		
	6.00	402.20	52.19	23.00	461.80	0.97	7.58	3.83		
	2.50	404.70	52.51	44.50	506.30	1.02		17.80		
	1.00	405.70	52.64	13.00	519.30	1.03	7.98	13.00		
	1.00	406.70	52.77	41.00	560.30	1.08		41.00		
	0.50	407.20	52.84	28.50	588.80	1.11	8.39	57.00		
	1.50	408.70	53.03	84.00	672.80	1.21		56.00		
	1.00	409.70	53.16	26.50	699.30	1.24	9.10	26.50		
	4.50	414.20	53.74	79.50	778.80	1.33		17.67		0.04
	1.00	415.20	53.87	27.00	805.80	1.37	8.93	27.00		
	2.50	417.70	54.20	76.50	882.30	1.45		30.60		0.04
	1.00	418.70	54.33	26.00	908.30	1.48	9.37	26.00		
	4.00	422.70	54.85	82.00	990.30	1.58		20.50		0.08
	0.50	423.20	54.91	28.00	1018.30	1.61	9.48	56.00		0.04
807.00	3.00	426.20	55.30	131.00	1149.30	1.76	9.51	43.67		0.04

TABLE E 2.

CORE 2.

RUN 13.

CORE PROPERTIES

POROSITY	= 43.06	PERCENT
PERMEABILITY	=364.20	MD
PORE VOLUME	=870.72	CC
INITIAL WATER SAT.	=152.92	CC
INITIAL OIL IN PLACE	=717.80	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.56	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 4.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	32.00	32.00	4.46			0.04				
	31.70	63.70	8.87	0.80	0.80	0.07		0.03		
	30.50	94.20	13.12	2.00	2.80	0.11		0.07	42809.00	
	52.00	146.20	20.37	45.00	47.80	0.22	6.63	0.87	31465.00	
53.00	4.00	150.20	20.93	4.50	52.30	0.23		1.13	24197.00	
87.00	27.50	177.70	24.76	61.50	113.80	0.33		2.24		
107.00	11.50	189.20	26.36	22.00	135.80	0.37		1.91	19411.00	
	37.50	226.70	31.58	44.00	179.80	0.47	7.26	1.17		
	33.00	259.70	36.18	56.00	235.80	0.57		1.70	24108.00	
	9.50	269.20	37.50	19.50	255.30	0.60	7.04	2.05		
	59.50	328.70	45.79	87.50	342.80	0.77		1.47	27122.00	
	38.50	367.20	51.16	50.00	392.80	0.87	7.46	1.30	27122.00	
	18.50	385.70	53.73	42.00	434.80	0.94	8.02	2.27	24906.00	
	9.50	395.20	55.06	20.50	455.30	0.98		2.16		0.12
	9.50	404.70	56.38	21.50	476.80	1.01	12.02	2.26		
	7.00	411.70	57.36	23.50	500.30	1.05		3.36		0.34
340.00	8.50	420.20	58.54	22.00	522.30	1.08		2.59		
	7.00	427.20	59.52	23.00	545.30	1.12	12.79	3.29		0.82
	14.00	441.20	61.47	46.00	591.30	1.19		3.29		
	5.50	446.70	62.23	24.00	615.30	1.22	13.00	4.36		1.02
	8.50	455.20	63.42	51.50	666.80	1.29		6.06		
	3.00	458.20	63.83	27.00	693.80	1.32	12.60	9.00		0.48
	3.00	461.20	64.25	57.00	750.80	1.39		19.00		
	0.50	461.70	64.32	30.50	781.30	1.43	12.28	61.00		0.20
	1.50	463.20	64.53	60.50	841.80	1.50		40.33		
	0.50	463.70	64.60	91.00	932.80	1.60	12.09	182.00		0.15
510.00	1.50	465.20	64.81	108.00	1040.80	1.73	11.80	72.00		0.13

TABLE E 3.

CORE 3.

RUN 14.

CORE PROPERTIES

POROSITY	= 42.80	PERCENT
PERMEABILITY	=373.00	MD
PORE VOLUME	=886.90	CC
INITIAL WATER SAT.	=165.90	CC
INITIAL OIL IN PLACE	=721.00	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.57	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 8.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	66.70	66.70	9.25	2.80	2.80	0.08		0.04	47241.00	
	69.90	136.60	18.95	29.10	31.90	0.19		0.42		
51.00	13.00	149.60	20.75	20.00	51.90	0.23	6.72	1.54	21863.00	
86.00	41.00	190.60	26.44	68.50	120.40	0.35		1.67		
	18.50	209.10	29.00	15.00	135.40	0.39	6.83	0.81		
	8.50	217.60	30.18	8.50	143.90	0.41		1.00	22611.00	
	38.50	256.10	35.52	58.50	202.40	0.52		1.52		
	12.00	268.10	37.18	21.00	223.40	0.55		1.75	29319.00	
	12.00	280.10	38.85	21.00	244.40	0.59	6.91	1.75		
	38.50	318.60	44.19	59.50	303.90	0.70		1.55		
336.00	36.50	355.10	49.25	61.00	364.90	0.81		1.67	31908.00	
	4.00	359.10	49.81	25.00	389.90	0.84	9.98	6.25		
	3.00	362.10	50.22	29.50	419.40	0.88		9.83		0.24
345.00	36.00	398.10	55.21	79.00	498.40	1.01		2.19		
	9.50	407.60	56.53	23.00	521.40	1.05		2.42		3.51
	10.00	417.60	57.92	22.00	543.40	1.08	13.26	2.20		
	19.50	437.10	60.62	45.50	588.90	1.16		2.33		
	9.50	446.60	61.94	23.50	612.40	1.19		2.47		2.77
	27.50	474.10	65.76	71.00	683.40	1.31	13.22	2.58		
	8.00	482.10	66.87	25.00	708.40	1.34		3.13		2.00
727.00	21.00	503.10	69.78	78.00	786.40	1.45		3.71		
	5.00	508.10	70.47	28.00	814.40	1.49		5.60		0.37
	4.00	512.10	71.03	30.00	844.40	1.53	12.61	7.50		
	5.50	517.60	71.79	61.00	905.40	1.60		11.09		
	1.50	519.10	72.00	31.50	936.90	1.64		21.00		0.25
	1.00	520.10	72.14	65.50	1002.40	1.72		65.50		
735.00	0.50	520.60	72.21	19.50	1021.90	1.74	12.09	39.00		0.16

TABLE E 4.

CORE 9.

RUN 15.

CORE PROPERTIES

POROSITY	= 44.21	PERCENT
PERMEABILITY	=457.00	MD
PORE VOLUME	=894.72	CC
INITIAL WATER SAT.	=211.12	CC
INITIAL OIL IN PLACE	=683.60	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 1.71	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	89.00	89.00	13.02			0.10				
	14.50	103.50	15.14	6.00	6.00	0.12		0.41	35807.00	
	44.00	147.50	21.58	40.00	46.00	0.22	7.08	0.91		
32.00	9.00	156.50	22.89	15.50	61.50	0.24		1.72	28451.00	
	10.50	167.00	24.43	29.50	91.00	0.29		2.81	25969.00	
50.00	24.00	191.00	27.94	59.00	150.00	0.38		2.46		
	14.00	205.00	29.99	29.50	179.50	0.43	7.22	2.11		
	9.00	214.00	31.30	11.00	190.50	0.45		1.22	26342.00	
	57.00	271.00	39.64	78.50	269.00	0.60		1.38		
	8.00	279.00	40.81	12.50	281.50	0.63	7.89	1.56		
	7.50	286.50	41.91	13.00	294.50	0.65		1.73		
	7.50	294.00	43.01	13.00	307.50	0.67	9.33	1.73		0.04
	19.00	313.00	45.79	42.00	349.50	0.74	12.45	2.21		
	5.00	318.00	46.52	15.00	364.50	0.76		3.00		0.86
146.00	8.50	326.50	47.76	32.00	396.50	0.81	13.10	3.76		
	4.50	331.00	48.42	16.00	412.50	0.83		3.56		
	3.50	334.50	48.93	16.50	429.00	0.85		4.71		1.51
	14.50	349.00	51.05	46.50	475.50	0.92	13.26	3.21		
	5.50	354.50	51.86	15.00	490.50	0.94		2.73		2.00
	17.50	372.00	54.42	43.50	534.00	1.01		2.49		
	6.50	378.50	55.37	13.50	547.50	1.03	13.14	2.08		1.53
	20.00	398.50	58.29	41.50	589.00	1.10		2.07		
	6.00	404.50	59.17	14.50	603.50	1.13		2.42		1.12
	13.00	417.50	61.07	28.00	631.50	1.17	13.03	2.15		
	13.00	430.50	62.98	28.00	659.50	1.22		2.15		0.86
	19.00	449.50	65.75	43.00	702.50	1.29		2.26		
	5.50	455.00	66.56	15.00	717.50	1.31	12.91	2.73		0.71
224.00	23.00	478.00	69.92	65.00	782.50	1.41		2.83		0.57
	12.00	490.00	71.68	50.00	832.50	1.48	12.67	4.17		
	3.50	493.50	72.19	17.50	850.00	1.50		5.00		0.37
	6.50	500.00	73.14	56.00	906.00	1.57		8.62		
	2.00	502.00	73.43	19.00	925.00	1.59		9.50		0.20
	3.50	505.50	73.95	59.00	984.00	1.66	12.15	16.86		
	0.50	506.00	74.02	20.00	1004.00	1.69		40.00		0.16
	3.50	509.50	74.53	80.00	1084.00	1.78		22.86		
	2.50	512.00	74.90	85.00	1169.00	1.88		34.00		

TABLE E 5.

CORE 4.

RUN 16.

CORE PROPERTIES

POROSITY	= 46.00	PERCENT
PERMEABILITY	=209.16	MD
PORE VOLUME	=495.25	CC
INITIAL WATER SAT.	= 97.63	CC
INITIAL OIL IN PLACE	=397.62	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 3.13	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
						0.05				
95.00	26.50	26.50	6.66			0.08		0.05		
	10.50	37.00	9.31	0.50	0.50	0.10	7.64	0.39	21803.00	
	9.00	46.00	11.57	3.50	4.00	0.15	7.81	0.53	16308.00	
80.00	17.00	63.00	15.84	9.00	13.00	0.20	7.78	1.08	16072.00	
	12.00	75.00	18.86	13.00	26.00	0.24	7.96	0.86		
70.00	10.50	85.50	21.50	9.00	35.00	0.29	8.00	3.67	15602.00	
60.00	4.50	90.00	22.63	16.50	51.50	0.36		4.85		
	6.50	96.50	24.27	31.50	83.00	0.41	8.00	5.00		
	4.00	100.50	25.28	20.00	103.00	0.48		8.14		
	3.50	104.00	26.16	28.50	131.50	0.50	8.49	5.50	14017.00	0.10
40.00	2.00	106.00	26.66	11.00	142.50	0.55		11.75		
	2.00	108.00	27.16	23.50	166.00	0.58	13.20	7.33	13915.00	2.00
	1.50	109.50	27.54	11.00	177.00	0.63		11.50		
	2.00	111.50	28.04	23.00	200.00	0.71	13.05	24.33		1.64
25.00	1.50	113.00	28.42	36.50	236.50	0.76		8.33		
20.00	3.00	116.00	29.17	25.00	261.50	0.82		17.67		
	1.50	117.50	29.55	26.50	288.00	0.85	13.06	7.50	4558.00	0.96
	2.00	119.50	30.05	15.00	303.00	0.93		8.75		
	4.00	123.50	31.06	35.00	338.00	0.97	12.56	9.50	4121.00	0.54
	2.00	125.50	31.56	19.00	357.00	1.07		11.38	4000.00	
20.00	4.00	129.50	32.57	45.50	402.50	1.10	12.39	12.50	5359.00	0.33
	1.00	130.50	32.82	12.50	415.00	1.18		14.00		
	2.50	133.00	33.45	35.00	450.00	1.27		18.20		
	2.50	135.50	34.08	45.50	495.50	1.44		31.80		
	2.50	138.00	34.71	79.50	575.00	1.76		19.13		
	8.00	146.00	36.72	153.00	728.00	2.00		46.20		
	2.50	148.50	37.35	115.50	843.50	2.13		41.00		
	1.50	150.00	37.72	61.50	905.00	2.30		23.00		
	3.50	153.50	38.60	80.50	985.50					

TABLE E 6.

CORE 6.

RUN 17.

CORE PROPERTIES

POROSITY	= 45.00	PERCENT
PERMEABILITY	=260.58	MD
PORE VOLUME	=484.32	CC
INITIAL WATER SAT.	= 98.36	CC
INITIAL OIL IN PLACE	=385.96	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 1.74	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	34.00	34.00	8.81			0.07				
100.00	13.00	47.00	12.18	2.00	2.00	0.10		0.15		
70.00	10.00	57.00	14.77	5.00	7.00	0.13		0.50	28362.00	
60.00	19.00	76.00	19.69	23.00	30.00	0.22		1.21	24817.00	
70.00	2.50	78.50	20.34	4.50	34.50	0.23	7.80	1.80	24373.00	
80.00	31.50	110.00	28.50	45.00	79.50	0.39		1.43		
	5.00	115.00	29.80	14.00	93.50	0.43	7.70	2.80	24000.00	
	21.00	136.00	35.24	54.50	148.00	0.59	12.29	2.60		0.10
80.00	4.00	140.00	36.27	26.00	174.00	0.65	12.98	6.50	19144.00	
	15.50	155.50	40.29	72.50	246.50	0.83	13.00	4.68		1.00
	4.50	160.00	41.46	21.00	267.50	0.88	12.84	4.67	9075.00	0.80
90.00	9.00	169.00	43.79	42.00	309.50	0.99		4.67		
90.00	4.00	173.00	44.82	21.50	331.00	1.04	12.62	5.38		0.44
80.00	13.00	186.00	48.19	68.00	399.00	1.21		5.23	3342.00	
	7.00	193.00	50.01	23.00	422.00	1.27	12.48	3.29		0.32
75.00	8.00	201.00	52.08	68.00	490.00	1.43		8.50	2481.00	
70.00	2.00	203.00	52.60	24.00	514.00	1.48	12.18	12.00		0.19
60.00	7.00	210.00	54.41	71.00	585.00	1.64		10.14	1949.00	
60.00	2.00	212.00	54.93	24.00	609.00	1.70	12.06	12.00		0.14
	6.00	218.00	56.48	97.00	706.00	1.91		16.17		

TABLE E 7.

CORE 6.

RUN 18.

CORE PROPERTIES

POROSITY	= 45.00	PERCENT
PERMEABILITY	=260.58	MD
PORE VOLUME	=484.32	CC
INITIAL WATER SAT.	=102.86	CC
INITIAL OIL IN PLACE	=381.46	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=20.00	CC/HR
SLUG SIZE OF WATER	= 0.00	PV
SLUG SIZE NAOH	= 1.82	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
200.00	42.00	42.00	11.01			0.09				
180.00	40.00	82.00	21.50			0.17				
300.00	20.00	102.00	26.74	23.00	23.00	0.26	12.36	1.15	44670.00	0.60
280.00	12.00	114.00	29.89	30.00	53.00	0.34		2.50		
250.00	4.00	118.00	30.93	17.00	70.00	0.39	12.95	4.25	32084.00	2.04
200.00	15.00	133.00	34.87	47.00	117.00	0.52	13.22	3.13		4.23
	5.50	138.50	36.31	19.00	136.00	0.57		3.45		
	4.50	143.00	37.49	18.50	154.50	0.61	13.03	4.11	17371.00	4.78
	12.00	155.00	40.63	59.00	213.50	0.76		4.92		
150.00	7.50	162.50	42.60	40.50	254.00	0.86		5.40		
	2.50	165.00	43.25	20.50	274.50	0.91	13.06	8.20	6452.00	5.05
	7.00	172.00	45.09	63.00	337.50	1.05		9.00		
	2.00	174.00	45.61	23.00	360.50	1.10	13.07	11.50	5140.00	5.58
130.00	6.00	180.00	47.19	70.00	430.50	1.26		11.67		
130.00	2.00	182.00	47.71	20.50	451.00	1.31	13.07	10.25	2853.00	5.51
	6.50	188.50	49.42	61.50	512.50	1.45		9.46		
130.00	2.00	190.50	49.94	21.00	533.50	1.49	13.07	10.50	1772.00	5.66
100.00	6.00	196.50	51.51	61.50	595.00	1.63		10.25		
	2.00	198.50	52.04	21.00	616.00	1.68	13.07	10.50	1329.00	5.74
	5.00	203.50	53.35	64.00	680.00	1.82		12.80		

TABLE E 8.

CORE 5.

RUN 19.

CORE PROPERTIES

POROSITY	= 45.00	PERCENT
PERMEABILITY	=258.50	MD
PORE VOLUME	=485.27	CC
INITIAL WATER SAT.	= 75.20	CC
INITIAL OIL IN PLACE	=410.07	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=50.00	CC/HR
SLUG SIZE OF WATER	= 1.86	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL. CONC (PPM)	NAOH CONC (%)
220.00	21.00	21.00	5.12			0.04				
210.00	25.00	46.00	11.22			0.09				
130.00	27.00	73.00	17.80	16.00	16.00	0.18		0.59		
86.00	9.00	82.00	20.00	21.00	37.00	0.25		2.33		
80.00	4.00	86.00	20.97	16.00	53.00	0.29	7.92	4.00	18411.00	
	6.00	92.00	22.44	28.00	81.00	0.36		4.67		
	4.00	96.00	23.41	30.00	111.00	0.43	11.59	7.50		0.10
	3.00	99.00	24.14	18.00	129.00	0.47		6.00		
	5.00	104.00	25.36	30.00	159.00	0.54	12.94	6.00	7976.00	3.09
50.00	4.00	108.00	26.34	31.00	190.00	0.61		7.75		
50.00	2.50	110.50	26.95	31.50	221.50	0.68	12.91	12.60		2.91
40.00	3.00	113.50	27.68	31.00	252.50	0.75		10.33		
	4.00	117.50	28.65	30.00	282.50	0.82	12.61	7.50	2292.00	0.77
	4.00	121.50	29.63	30.00	312.50	0.89		7.50		
30.00	3.00	124.50	30.36	31.00	343.50	0.96	12.13	10.33		0.26
	3.00	127.50	31.09	31.00	374.50	1.03		10.33		
	3.00	130.50	31.82	31.00	405.50	1.10	11.79	10.33	1575.00	0.13
	3.00	133.50	32.56	31.00	436.50	1.17		10.33		
	3.00	136.50	33.29	31.00	467.50	1.24		10.33		
	2.00	138.50	33.77	32.00	499.50	1.31		16.00		
25.00	2.00	140.50	34.26	32.00	531.50	1.38	11.37	16.00	1418.00	0.12
	2.00	142.50	34.75	32.00	563.50	1.45		16.00		
	1.00	143.50	34.99	14.00	577.50	1.49		14.00		
	2.50	146.00	35.60	21.50	599.00	1.54		8.60		
25.00	1.00	147.00	35.85	33.00	632.00	1.61	10.86	33.00	1400.00	0.06
	1.00	148.00	36.09	34.00	666.00	1.68		34.00		
	1.00	149.00	36.34	33.00	699.00	1.75		33.00		
	1.00	150.00	36.58	33.00	732.00	1.82		33.00		
	1.00	151.00	36.82	33.00	765.00	1.89		33.00		
	1.00	152.00	37.07	33.00	798.00	1.96		33.00		
	1.00	153.00	37.31	33.00	831.00	2.03		33.00		

TABLE E 9.

CORE 8.

RUN 20.

CORE PROPERTIES

POROSITY	= 38.73	PERCENT
PERMEABILITY	= 1.53	D
PORE VOLUME	=417.30	CC
INITIAL WATER SAT.	= 68.56	CC
INITIAL OIL IN PLACE	=348.74	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 1.85	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
	58.00	58.00	16.63			0.14				
20.00	36.00	94.00	26.95			0.23				
10.00	42.00	136.00	39.00	36.00	36.00	0.41		0.86		
	9.00	145.00	41.58	52.00	88.00	0.56	7.85	5.78	25703.00	
	4.00	149.00	42.73	57.00	145.00	0.70		14.25		
	2.00	151.00	43.30	16.00	161.00	0.75	8.40	8.00	8559.00	
5.00	3.00	154.00	44.16	31.00	192.00	0.83	12.50	10.33		0.88
	4.00	158.00	45.31	14.00	206.00	0.87		3.50		
	3.00	161.00	46.17	15.00	221.00	0.92	12.98	5.00	2215.00	3.32
	2.00	163.00	46.74	15.00	236.00	0.96		7.50		
	3.00	166.00	47.60	28.00	264.00	1.03		9.33		2.10
	2.00	168.00	48.17	28.00	292.00	1.10		14.00		
	3.00	171.00	49.03	52.00	344.00	1.23	12.64	17.33	1843.00	0.83
	6.00	177.00	50.75	83.00	427.00	1.45		13.83		
5.00	0.50	177.50	50.90	12.50	439.50	1.48	12.21	25.00		0.38
	2.50	180.00	51.61	23.50	463.00	1.54		9.40		0.09
	0.25	180.25	51.69	11.75	474.75	1.57	11.90	47.00	2798.00	
	1.50	181.75	52.12	38.00	512.75	1.66		25.33		
	0.20	181.95	52.17	12.80	525.55	1.70		64.00	1772.00	
	1.00	182.95	52.46	12.00	537.55	1.73		12.00		
	1.00	183.95	52.75	31.00	568.55	1.80		31.00		
	1.00	184.95	53.03	29.00	597.55	1.88		29.00		
	2.00	186.95	53.61	58.00	655.55	2.02		29.00		

TABLE E 10.

CORE 7.

RUN 21.

CORE PROPERTIES

POROSITY	= 38.67	PERCENT
PERMEABILITY	= 1.55	D
PORE VOLUME	=420.15	CC
INITIAL WATER SAT.	= 99.07	CC
INITIAL OIL IN PLACE	=321.08	CC

EXPERIMENTAL VARIABLES

RATE OF INJECTION	=12.00	CC/HR
SLUG SIZE OF WATER	= 1.85	PV
SLUG SIZE NAOH	= 0.17	PV
CONCENTRATION NAOH	= 6.00	WT-PC
TEMPERATURE	=80.00	F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
180.00	29.00	29.00	9.03			0.07				
100.00	10.50	39.50	12.30	15.00	15.00	0.13	7.43	1.43	30844.00	
60.00	5.00	44.50	13.86	20.00	35.00	0.19		4.00		
20.00	6.00	50.50	15.73	20.00	55.00	0.25		3.33		
	6.00	56.50	17.60	23.00	78.00	0.32	7.61	3.83	6736.00	
	6.00	62.50	19.47	24.00	102.00	0.39	10.90	4.00		0.30
20.00	4.00	66.50	20.71	21.00	123.00	0.45		5.25		
	5.50	72.00	22.42	15.00	138.00	0.50	13.30	2.73	5601.00	4.82
	5.00	77.00	23.98	20.00	158.00	0.56		4.00	2658.00	
15.00	13.00	90.00	28.03	38.00	196.00	0.68		2.92		
	9.00	99.00	30.83	16.00	212.00	0.74	12.85	1.78	8863.00	0.91
	6.00	105.00	32.70	20.00	232.00	0.80		3.33		
	6.50	111.50	34.73	19.00	251.00	0.86		2.92		0.40
	6.50	118.00	36.75	20.00	271.00	0.93		3.08		
15.00	5.50	123.50	38.46	20.00	291.00	0.99	12.27	3.64	8154.00	0.23
	6.00	129.50	40.33	44.00	335.00	1.11		7.33		
	3.00	132.50	41.27	22.00	357.00	1.17		7.33		
	3.00	135.50	42.20	22.00	379.00	1.22	11.68	7.33	6381.00	0.19
	8.00	143.50	44.69	67.00	446.00	1.40		8.38		
	2.00	145.50	45.32	22.50	468.50	1.46	11.43	11.25	3368.00	0.11
	5.50	151.00	47.03	46.00	514.50	1.58		8.36		
	2.00	153.00	47.65	22.00	536.50	1.64		11.00		
	3.00	156.00	48.59	22.00	558.50	1.70		7.33	2836.00	
15.00	5.00	161.00	50.14	46.00	604.50	1.82		9.20		
	3.00	164.00	51.08	49.00	653.50	1.95		16.33		
	3.00	167.00	52.01	27.00	680.50	2.02		9.00		

TABLE E 11.

CORE 11.

RUN 22.

CORE PROPERTIES		EXPERIMENTAL VARIABLES	
POROSITY	= 40.16 PERCENT	RATE OF INJECTION	= 2.5 CC/HR
PERMEABILITY	= 62.90 MD	SLUG SIZE OF WATER	= 1.44 PV
PORE VOLUME	= 436.78 CC	SLUG SIZE NAOH	= 0.15 PV
INITIAL WATER SAT.	= 84.98 CC	CONCENTRATION NAOH	= 6.0 WT %
INITIAL OIL IN PLACE	= 351.80 CC	TEMPERATURE	= 80° F

PRESS CHANGE (PSI)	OIL PROD (CC)	CUM OIL PROD (CC)	PER CENT OF IOIP	WATER PROD (CC)	CUM WATER PROD (CC)	CUM TOTAL INJ (%PV)	PH OF WATER PROD	W.O.R.	CL CONC (PPM)	NAOH CONC (%)
292.2	9.5	9.5	2.7	-	0	2.2		0		
213.4	7.5	17.0	4.8	-	0	3.9		0		
124.2	29.0	46.0	13.1	8.0	8.0	12.4		0.28	49281	
111.2	4.5	50.5	14.4	9.5	17.5	15.6	6.53	2.11		
	5.5	56.0	15.9	10.5	28.0	19.2		1.91		
103.2	3.5	59.5	16.9	10.0	38.0	22.3		2.86	45634	
116.0	7.5	67.0	19.0	31.5	69.5	31.3	6.75	4.20		
156.0	4.5	71.5	20.3	9.0	78.5	34.3		2.00		
	13.5	85.0	24.2	27.0	105.5	43.6	6.96	2.00		
500	5.5	90.5	25.7	16.5	122.0	48.7		3.00	22808	
600	9.0	99.5	28.3	27.5	149.5	57.0	7.60	3.06		
650	5.5	105.0	29.8	11.0	160.5	60.8		2.00		
	17.5	122.5	34.8	19.0	179.5	69.1	9.39	1.09		0.04
700	7.0	129.5	36.8	14.5	194.0	74.1		2.07		
	11.0	140.5	39.9	26.0	220.0	82.5	11.53	2.36		0.22
	4.0	144.5	41.1	15.0	235.0	86.9		3.75		
850	9.0	153.5	43.6	31.0	266.0	96.0		3.44		0.24
	2.5	156.0	44.3	17.5	283.5	100.6	11.69	7.00		
	5.5	161.5	45.9	32.5	316.0	109.3		5.91		0.22
925	1.5	163.0	46.3	19.5	335.5	114.1		13.00		
	2.5	165.5	47.0	36.5	372.0	123.1		19.60		0.12
1000	0.5	166.0	47.2	21.5	393.5	128.1	10.93	43.00		
	1.0	167.0	47.5	39.5	433.0	137.4		39.50		0.12
1000	0.5	167.5	47.6	36.5	469.5	145.8		73.00		
	0.5	168.0	47.8	15.5	485.0	149.5		31.00		0.10
1000	0.5	168.5	47.9	40.0	525.0	158.8	10.87	80.00		

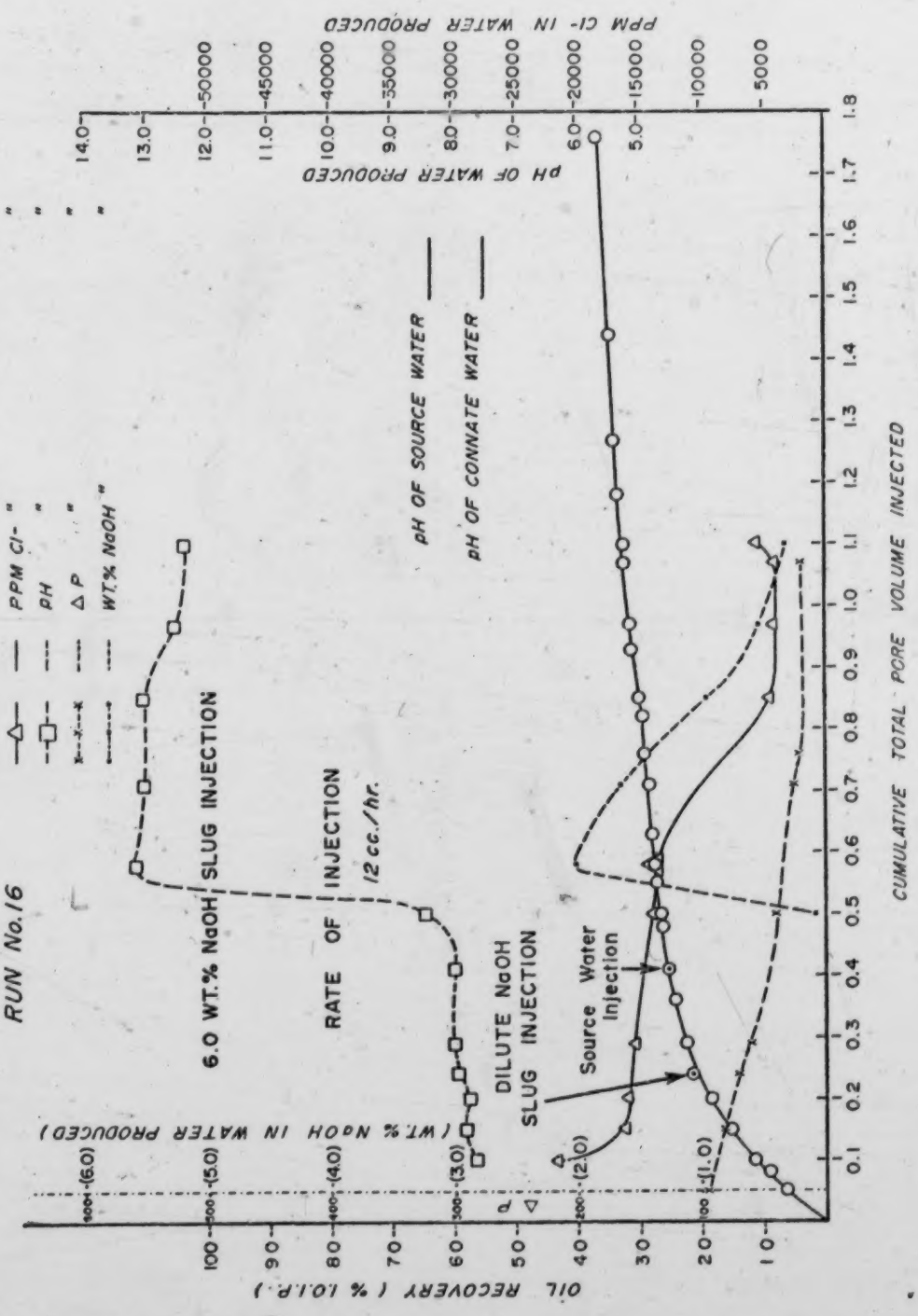

% I.O.I.P vs. CUM. TOTAL Pv INJECTED
PPM Cl- "
pH "
ΔP "
WT.% NaOH "
pH OF SOURCE WATER
pH OF CONNATE WATER
6.0 WT.% NaOH SLUG INJECTION
RATE OF INJECTION 12 cc./hr.
DILUTE NaOH SLUG INJECTION
Source Water Injection
OIL RECOVERY (% I.O.I.P.)
(WT.% NaOH IN WATER PRODUCED)
pH OF WATER PRODUCED
PPM Cl- IN WATER PRODUCED
CUMULATIVE TOTAL PORE VOLUME INJECTED

FIG. E-1 PERFORMANCE OF CAUSTIC WATERFLOOD ON 1 1/2" DIAMETER CORE NO.4
1 1/2" CORE No. 4
RUN No.16

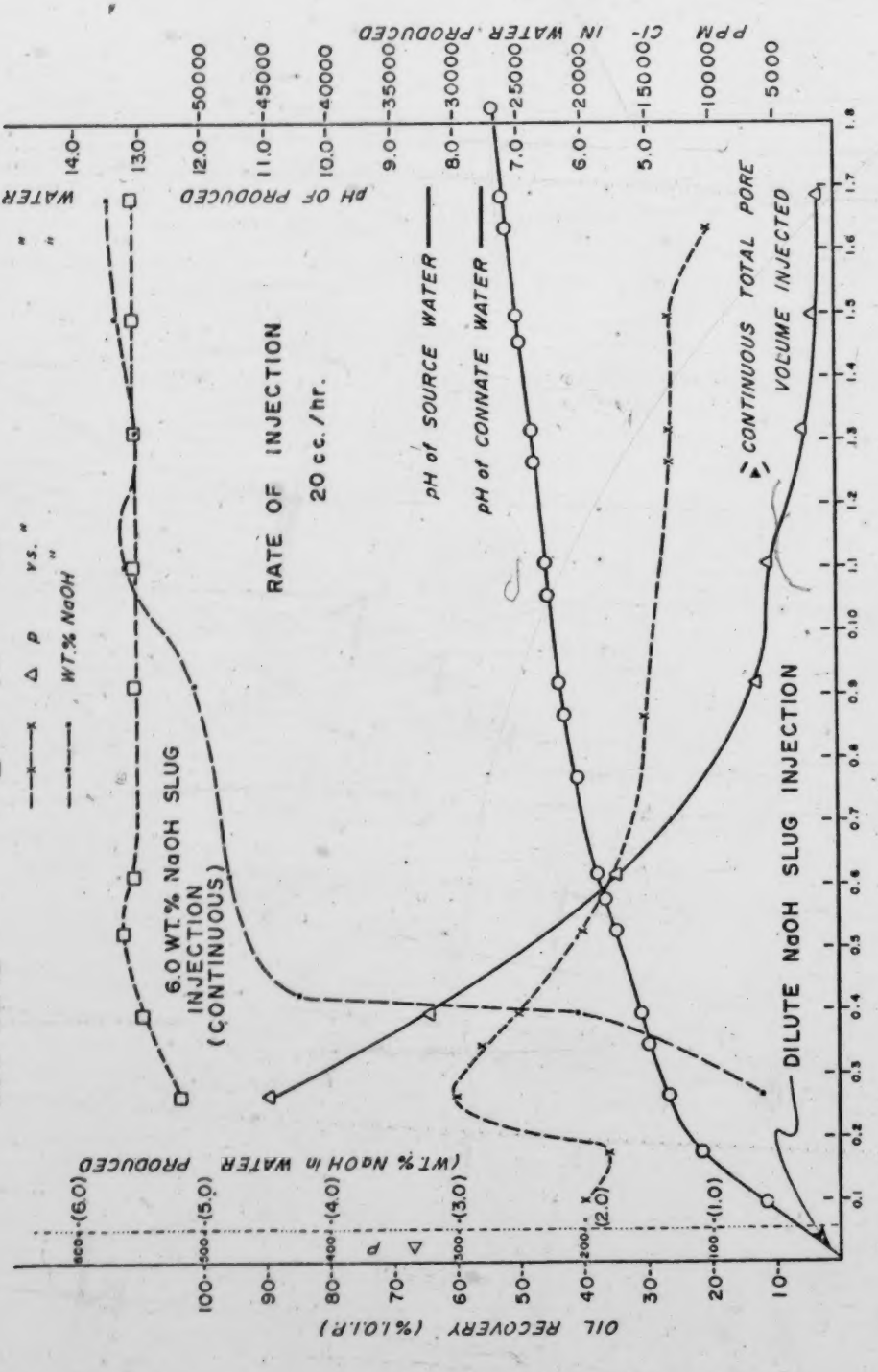


FIG. E-2 EFFECT OF CONTINUOUS CAUSTIC INJECTION ON OIL RECOVERY RESULTS

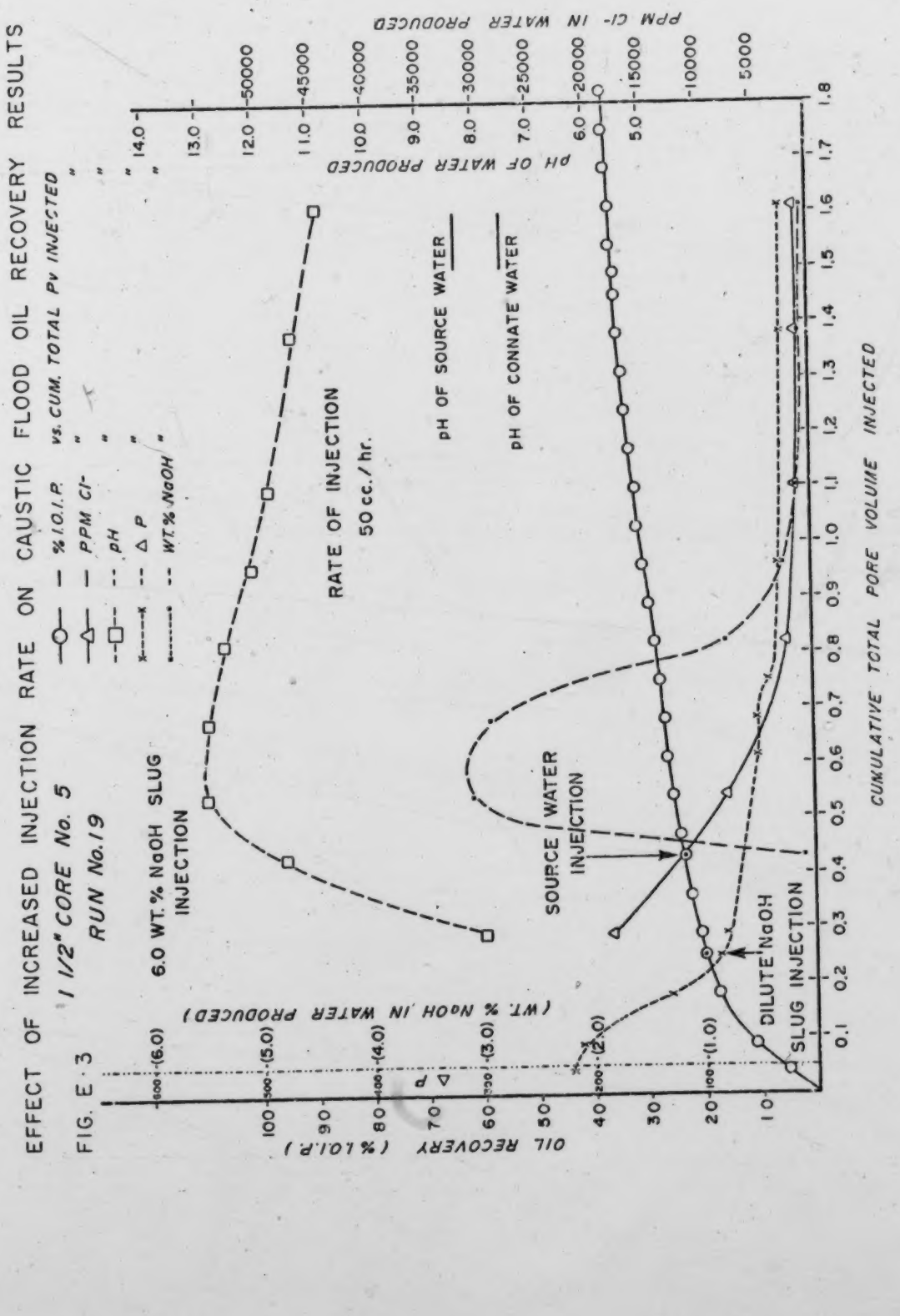

EFFECT OF INCREASED INJECTION RATE ON CAUSTIC FLOOD OIL RECOVERY RESULTS
1 1/2" CORE No. 5
RUN No.19
% I.O.I.P. vs. CUM. TOTAL Pv INJECTED
PPM Cl- "
pH "
Δ P "
WT.% NaOH "
6.0 WT.% NaOH SLUG INJECTION
RATE OF INJECTION 50 cc./hr.
pH OF SOURCE WATER
pH OF CONNATE WATER
SOURCE WATER INJECTION
DILUTE NaOH SLUG INJECTION
OIL RECOVERY (% I.O.I.P.)
(WT. % NaOH IN WATER PRODUCED)
pH OF WATER PRODUCED
PPM Cl- IN WATER PRODUCED
CUMULATIVE TOTAL PORE VOLUME INJECTED

FIG. E·3

FIG. E-4 EFFECT OF DIFFERENT SAND ON CAUSTIC FLOOD OIL RECOVERY RESULTS

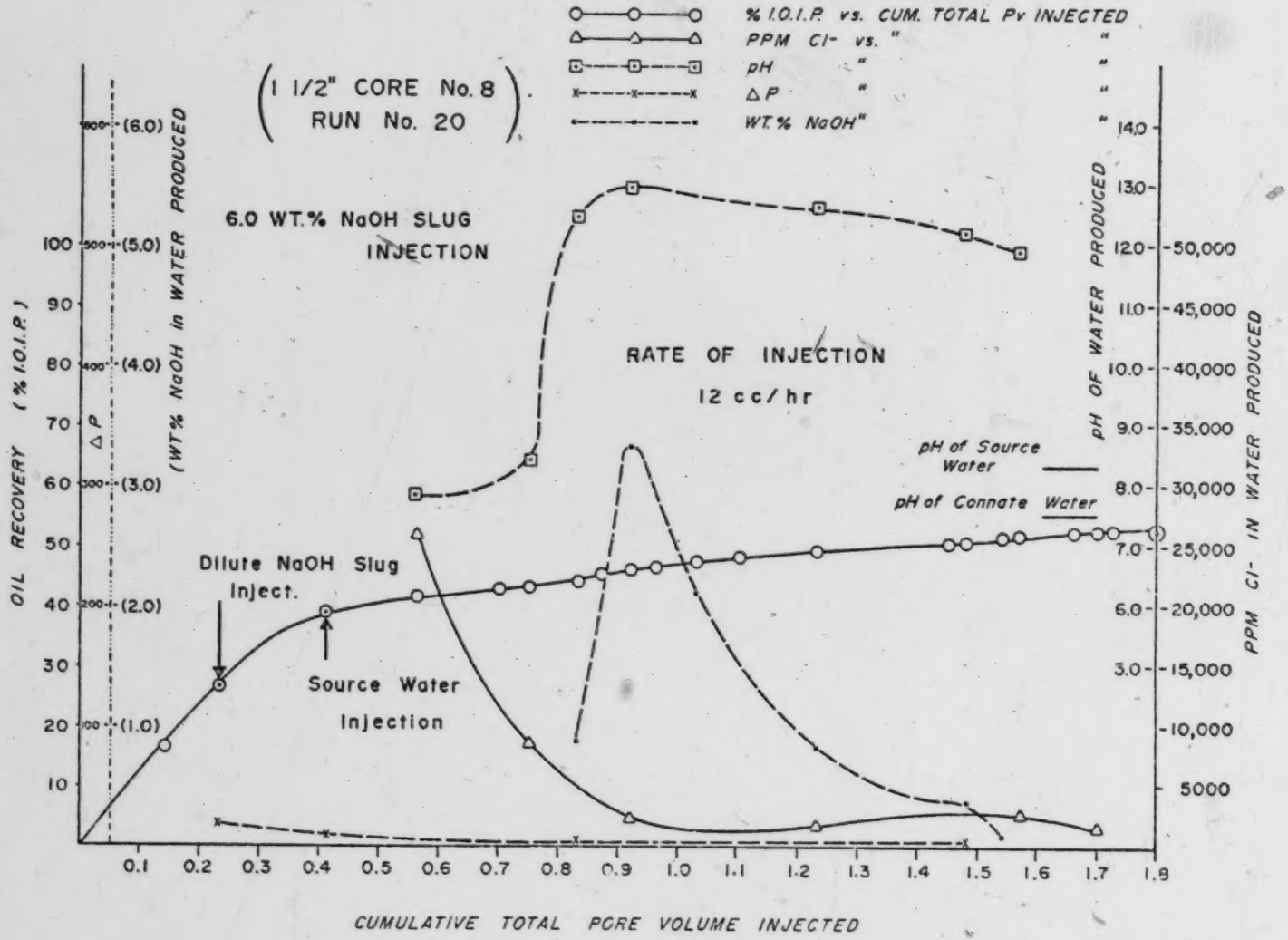


FIG. E-5 EFFECT OF UNDILUTED CRUDE ON CAUSTIC FLOOD OIL RECOVERY RESULTS